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ARGONNE NATIONAL LABORATORY

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WESTERN TIGHT SANDS GAS DEVELOPMENT: ECONOMIC AND REGULATORY ASPECTS OF BLANKET RESOURCE SUPPLY

Final Report: March 1981 - May 1983

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Final Report: March 1981 - May 1983

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EXECUTIVE SUMMARY

The purpose of this study is to assess the recoverable quantities and extraction costs of western tight sands gas from blanket formations. Tight sands gas is one of the four designated unconventional gas resources. Blanket tight sands gas is characterized by its deposition in continuous rock strata of low permeability and thereby results in a low production rate in the absence of artificial stimulation. In this report, the only stimulation method we consider is massive hydraulic fracturing (MHF). Furthermore, in this study, we specifically investigate how the quantities and extraction costs of blanket tight sands gas depend on and are affected by

(1) rate of return and risk premium,

(2) technology advancement,

(3) well-spacing and land use regulations, and

(4) impediments to near-term development.

The results of this assessment are shown as families of marginal cost curves or resource supply curves. These curves illustrate the sensitivity of the recoverable resource and extraction costs to the cases analyzed.

TIGHT SANDS GAS RESOURCE

The size of the tight sands gas resource remaining to be discovered is projected to be very large. It is estimated that the amount of potentially recoverable tight sands gas in the lower 48 states is almost equal to the recoverable conventional gas expected to be discovered. Specifically, the *Tight Gas Reservoirs* Task Group of the National Petroleum Council (NPC) Committee on Unconventional Gas Sources has estimated that about 600 trillion cubic feet (TCF) of undiscovered tight sands gas is recoverable. Other resource assessments have also projected large quantities of recoverable tight sands gas.

A tight gas sands formation is defined in terms of its low in situ gas permeability. Permeability is a measure of the ability of the gas to flow through the sandstone source rock. The Federal Energy Regulatory Commission (FERC) defines tight sands gas as that found in formations with an average in situ permeability of 0.1 millidarcies (md) or less. Tight formation gas qualifies for incentive pricing under Section 107 of the Natural Gas Policy Act of 1978 (NGPA).

In addition to low permeability, other common geologic characteristics make tight sands gas more challenging to develop. High levels of water saturation reduce the volume of pore space in the source rock available to contain gas (i.e., low gas-filled porosity). Water saturation may also impede gas production. The presence of clays and shales in some regions may make tight sands gas harder to find (i.e., interfere with gas detection and reservoir parameter measurement) and harder to extract using well stimulation technologies.

In the Rocky Mountain region most of the tight sands gas is in lenticular formations, consisting of multiple gas-bearing lenses of fluvial (river basin) origin. The lenses are typically interspersed in thick sections of shale and clay strata. In contrast, more continuous gas-bearing sandstone strata are called blanket formations. Blanket sands formations are prevalent in the Northern Great Plains and the Southwest regions.

For the analysis described here, only blanket sand formations are included. Technology currently exists to stimulate a well in blanket sands by creating a massive hydraulic fracture propagating in opposite directions from the well bore. Alternatively, the desired technology to develop lenticular sands is not sufficiently available. In lenticular regions it is desirable to contact several lenses remote from the well bore with a single fracture. Contacting remote lenses requires greater ability to control fracture propagation at rock interfaces, such as between sandstone and shale. Hence, this study includes only blanket formations, on which commercial development of tight sands gas is likely to focus in the near to medium term.

EXTRACTION COST, METHODOLOGY AND RESULTS

In this study, extraction costs are computed on the basis of dollars per thousand cubic feet ($/MCF). These extraction costs are based on numerous assumptions about geologic properties, technology performance, cost estimates, financial parameters, and regulations. The type of information required will be discussed briefly. Geologic properties include statistics on the relationship between in situ permeability, gas-filled porosity, net pay thickness, depth, pressure, and the areal extent of the tight sands gas resource. Extraction technology involves detecting tight gas sand zones, drilling and completing wells, and stimulating a zone (or sometimes multiple zones) with a fracture treatment to improve gas flow rates. The average fracture conductivity and average achieved fracture length from the well bore are critical measures of technology performance. Cost estimates corresponding to the extraction technology must be obtained. Financial parameters include tax rates, royalty and leasehold costs and the risk-adjusted cost of capital. Finally, well-spacing regulations may affect gas economics and ultimate recovery.

The kind of information described above was assembled by the NPC *Tight Gas Reservoirs* Task Group. Geologic data were collected by teams of geologists for twelve western basins in the Southwest, Rocky Mountain and Northern Great Plains regions. These data were analyzed using the Basin Risk

Analysis Model, which yields internal rates of return on average after-tax cash flows for each of a set of wellhead gas prices. Average cash flows were obtained using Monte Carlo simulation with 1000 trial runs for each case. The economic results are provided in the NPC report.

Extraction costs as reported in this report are obtained from the NPC economic results. Extraction costs are defined as the price per MCF of gas so that the average after-tax cash flow yields just the required rate of return, including a risk premium. That is, the extraction cost is the break-even price of gas. This break-even price was obtained from the NPC results by interpolating between discrete price levels in order to achieve a target rate of return, say 15%. It should be emphasized that in the NPC analysis, all the cash flows are in real terms, and hence, the computed extraction costs are also in real terms. This means that the break-even price must be allowed to increase at the same rate as inflation.

The results of our analysis are shown in the form of resource supply curves for blanket tight sands gas. Resource supply curves are constructed by sorting the quantities of tight sands gas in order of extraction cost. Extraction cost is then plotted vs. cumulative recoverable resources. Of course, the extraction cost depends on the required rate of return (including the risk premium). A family of resource supply curves is shown in Fig. ES-1 for 10%, 15% and 20% rates of return. The 15% curve shows, for example, that at a real wellhead price of $3.00 per MCF, about 70 TCF of blanket sands gas can be found, developed and produced economically.

Resource supply curves are also called marginal cost curves, since they yield the cost of producing an additional MCF of gas given any level of past cumulative production. For example, if 70 TCF of gas has already been produced, the extraction cost of the next unit is about $3.00/MCF with a 15% rate of return. Of course, the concept of a marginal cost curve depends on the resource being systematically produced in the most economical order, starting from the lowest cost grades.

The appropriate choice for the required rate of return depends on the cost of capital and the level of risk. Types of risk can be classified as geologic, technical, commercial and regulatory. No attempt is made here to estimate the cost of capital for producers of tight sands gas or to estimate market risk premiums. However, it can be noted that as the required return declines from 20% to 15%, extraction costs decrease on average 20.4%. Similarly, a change from a 15% to a 10% real rate of return decreases average extraction costs 24.6%.

Extraction costs are expressed in constant midyear 1981 dollars. A tight-gas-sands drilling cost index was applied to escalate the NPC results from January 1, 1979, dollars. The cost index was constructed by Ovid Baker based on Independent Petroleum Association of America (IPAA) data for tight gas sands depths and geographic regions. Baker estimates a 32.7% cost escalation to convert the NPC results to midyear 1981 dollars.

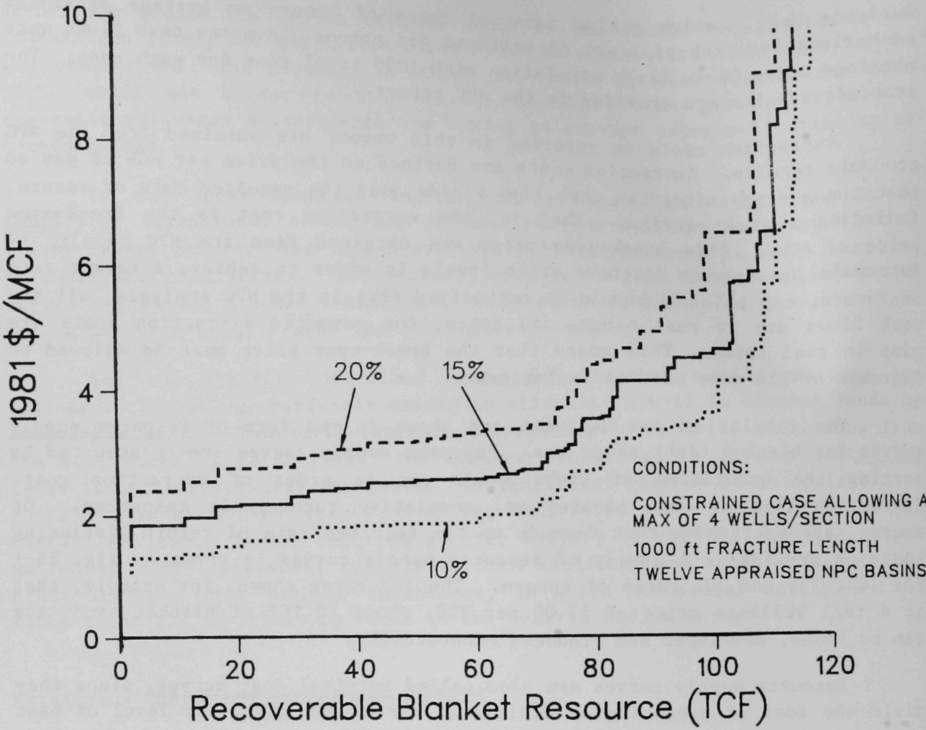

Fig. ES-1 Resource Supply Curves for Three Rates of Return

TECHNOLOGY ADVANCEMENT

Special technical challenges arise with respect to developing the tight sands gas resource. Detecting the resource, measuring reservoir parameters and fracturing the formation are all areas where current technology exists but continued improvements are expected. This report focuses on hydraulic fracturing technology.

Several key parameters characterize a fracture: created hydraulic length, achieved propped length, fracture height and fracture conductivity. For resource assessment purposes in the NPC report and in this report, the fracture is assumed to be designed for a created hydraulic length of 1700 ft. This length is the distance from the well bore to the tip of the fracture. The fracture is created by pumping fracture fluid into the formation at a controlled rate under very high pressure. The fluid contains a proppant, often sand, to hold open the fracture after the fracture fluid is pumped back up the well. The achieved length is the length of the fracture which is held open by the proppant. Typically, under current technology, a propped length of 60% to 70% of the created hydraulic length can be achieved.

Controlling fracture height is important so that the fracture contacts the gas pay interval. However, excessive heights should be avoided to reduce fracture treatment costs. Fracture heights of 200 ft to 300 ft are typical. The purpose of the fracture is to provide a surface (in the vertical plane) in contact with the formation. The fracture creates a flow channel to the well bore. The width of the fracture may be only 1/4 to 1/2 inch. Fracture conductivity depends on this width and the permeability of the proppant wedged into the fracture.

Fracturing technology has advanced rapidly in the past, and continued progress is expected. This report examines only technological improvements in the achieved propped fracture length as a fraction of the created hydraulic length. In other words, for a fixed expenditure on a fracture treatment, technical progress in the form of a longer achieved fracture length reduces the extraction cost of gas, measured in dollars per MCF. For a hydraulic length designed to be 1700 ft, empirical evidence from the mid- to late-1970s indicates an achieved length of 600 ft to 800 ft on average. Regarding current industry experience, the NPC Task Group on *Tight Gas Reservoirs* asserts that a 1000-ft achieved length represents the current state of technology. Through technical progress, the ratio of achieved length to hydraulic length can be increased, resulting in, for example, a 1200-ft effective fracture for the same cost of a fracture treatment assumed in the NPC report.

The average achieved fracture length can be increased in a number of ways. Fracture propagation and sand transport can be improved. Fracture fluids can be improved and fluid leak-off into the formation can be reduced. The frequency of "screen-outs" can be lowered. In a screen-out, the pumping of material slows down or stops causing pressure to increase due to the proppant becoming dry, building up and blocking further sand transport. Other possible fracturing problems include irregular proppant settling, proppant crushing under high pressure and proppant embedment in the formation pores, restricting gas flow. Also, mechanical problems with the well completion or the fracture treatment can arise. These potential problems can affect the reliability of the fracture performance. Fracture reliability has improved substantially over time and should continue to improve.

Another important technology issue pertaining to tight gas sands is the desire to fracture multiple layers. In some basins, the pay thickness within a formation may be very great, while in other basins two or more formations can overlap with separating distances being substantial. Performing separate fracture jobs on each layer is very costly. Several technologies, such as using limited entry or ball sealers, exist for fracturing multiple layers, but these methods introduce additional complications and risk. For example, the volume of fracture fluid entering each layer may be difficult to control precisely.

For resource assessment purposes, the average effective fracture length is needed. In computing average fracture length, one must be careful not to exclude the fractures which do not perform well, for the reasons discussed above. That is, the average length depends on both the effective length of successful fractures and the frequency of unsuccessful fractures.

Figure ES-2 shows the effects of increased achieved fracture length on extraction cost reduction. Extraction costs shift down an average of 13.5% when the effective fracture length increases from 1000 ft to 1200 ft. (Recall that the cost for the fracture job is held fixed). The poorer permeability grades are more sensitive to fracture length, as indicated in Fig. ES-2 by larger percent reductions for high cost grades.

The effects of learning can improve technology and reduce risks simultaneously. For example, a more reliable MHF technology both increases the average fracture length as well as reduces risk. An average fracture

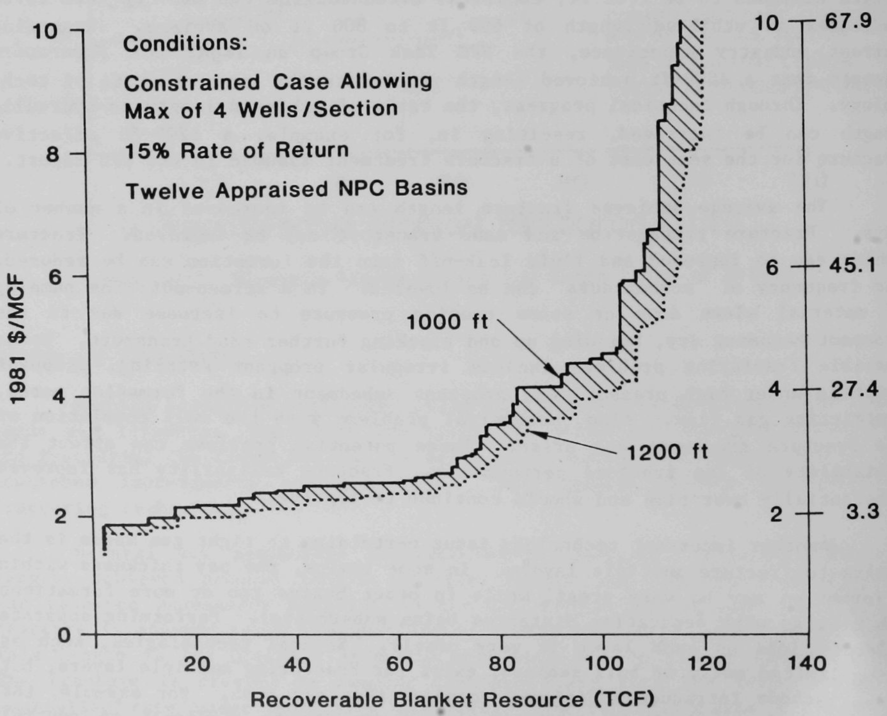

Fig. ES-2 Relationship between Higher Cost Grade Resources and Sensitivity to Average Fracture Length

length change from 1000 to 1200 ft, together with a reduction in the required rate of return (risk premium) from 15% real to 10%, yields a 35% reduction in extraction costs.

There are potentially large benefits from this technology advancement. Undiscounted benefits (not taking into account how far in the future the resource will eventually be developed) can be computed from the area between these two curves. Specifically, for a market wellhead price of $6.00/MCF, undiscounted benefits are $45.1 billion in midyear 1981 dollars. These benefits correspond to the area between the two curves and below $6.00. The benefits arise due to both reductions in the extraction cost of gas which is already economic and to additional resources becoming economic (i.e., economic resources in this example are defined to be those with extraction costs of less than $6.00).

It should be emphasized that the benefits reported here reflect only one aspect of technical advancement. Not considered are improved tight sands gas detection methods or the capability to design larger MHFs such as 4000 ft. Our present analysis could be thought of as holding fixed the hydraulic design length at 1700 ft while the propped length is increased from 60% to 72% of this hydraulic length. This technical change is a pure efficiency improvement. The Argonne methodology used to compute the effects of this type of efficiency improvement on the extraction costs of gas is described in Sec. 6 of this report.

Finally, the benefits resulting from fracture efficiency increases, as described above, are <u>minimum</u> benefits. Not included are benefits which would accrue to those tight sands resources excluded from the study. These exclusions are discussed next.

RESOURCES EXCLUDED FROM THE STUDY

The NPC *Tight Gas Reservoir* study, which provides the data for this report, appraised in detail twelve western tight sands gas basins. These basins represent about half of the recoverable tight gas resource expected to be discovered in the lower 48 states. The division of the appraised resource into the three major western regions -- Northern Great Plains, Rocky Mountains and the Southwest -- is shown in Fig. ES-3.

All of the resource in Northern Great Plains was appraised. However, the blanket sands gas there is considered to be more risky than in the other regions. The siltstone stringers containing gas are interspersed in clays and shales and hence difficult to detect. The resource density over the land area is low. Some formations are thick, and up to five formations may overlap with substantial distance separating them in some cases. The shallow wells require pumping and gas compression in the field. Further, most of the area is currently not accessible to a pipeline network.

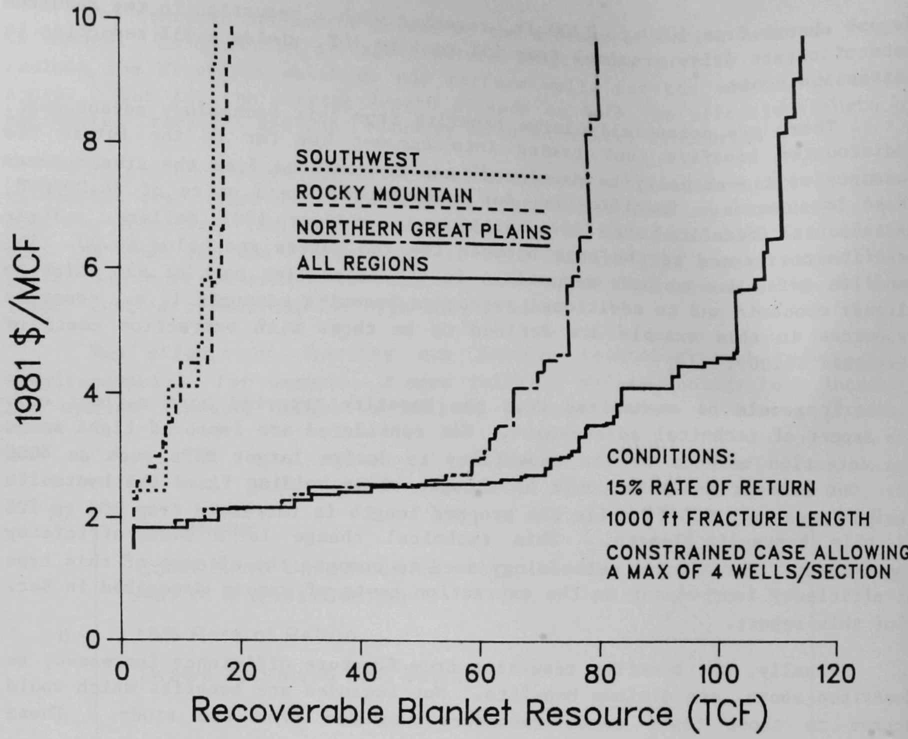

Fig. ES-3 Blanket Resource Supply Curves by Region

In the Southwest only about 20% of the tight sands gas resource was appraised in detail. However, this region is currently very active in producing tight sands gas. The Rocky Mountain area contains mostly lenticular sands. Nevertheless, significant quantities of blanket sands do exist there. About 10 TCF of blanket sands gas was not appraised in the Rocky Mountain region.

In view of the above discussion, the marginal cost curves presented in this report should be interpreted carefully. These curves are useful to show the effects of the required rate of return and fracture efficiency on the distribution of resource by cost grade. However, it should be clear from Fig. ES-3 that if the remaining 80% of the blanket resource in the Southwest had been included, the curves would appear substantially different in shape. Consequently, the full tight sands gas resource should be included for long-run energy sector modeling. Further adjustments and/or disaggregations should possibly be made to the resource supply curves to account for noncost differences such as pipeline accessibility and capacity availability.

In addition to extrapolated areas and lenticular sands, other tight gas resources excluded from the study are current tight gas reserves and gas in tight sands zones which can be developed by recompleting existing gas wells.

REGULATORY AND PIPELINE ACCESSIBILITY ISSUES

The primary regulatory issue analyzed in this report is the effect of well-spacing regulations on the recoverable tight sands gas resource. Typical state regulations allow 160-acre well spacing or a maximum of four wells per section (mi^2). This constraint was built into the NPC analysis and is incorporated into most of the marginal cost curves shown in this report. However, the effects of relaxing this regulation are also shown here. In summary, about 20 TCF of additional blanket gas would be recoverable without a well-spacing constraint.

Other regulatory issues analyzed in this report are (1) incentive pricing of tight formation gas under the NGPA, and (2) the possibility of land use restrictions affecting the development of tight sands gas.

Pipeline accessibility was also evaluated in this study. An assessment of the current pipeline network relative to the twelve appraised western tight sands gas basins and an examination of present and projected transmission capacities identified a number of potential constraints. Several conclusions were reached in this evaluation. It was found that there are many tight gas sands basins accessible to existing gas pipelines. Most Southwest and Rocky Mountain Basins are served by pipelines. However, access to pipelines in Northern Great Plains is a problem. The location of the existing and proposed pipelines within each region and basin may require the development of an extensive field and gathering system, and the construction of new interconnecting pipelines. Otherwise, particular formations and basins would have only limited accessibility to a transmission system for the tight sands gas.

RANKING OF THE BLANKET TIGHT SANDS BASINS

Within each region, Argonne ranked the basins appraised by NPC according to three factors: extraction cost, pipeline accessibility and technology adaptability. Some clear distinctions can be made between particular basins in each region. These distinctions can be seen in Table ES-1 which summarizes the basin ranking by region for the three factors addressed in this study. In particular, the Niobrara formation and the overlapping Niobrara and Carlile formations in the Northern Great Plains region are more capable of near-term development than the other formations in this region. Better pipeline accessibility and technology adaptability are key factors. Within the Rocky Mountain region, the Uinta, Piceance and Greater Green River Basins all have favorable development factors, although the Uinta Basin contributes around one-half of the economically recoverable resource in the region. In the Southwest region, the Cotton Valley Basin is by far the best basin for

Table ES-1 Comparison of Extraction Costs, Recoverable Resource, Pipeline Accessibility and State of Technology for Tight Sands Gas Basins in Three Western Regions[a]

Basins/Formations	Recoverable Blanket Resource (in TCF) Available at a Given Extraction Cost: 1000 ft Fracture, 15% Discount Rate, Constrained and Unconstrained Well Spacing Case						Qualitative Development Capability Rating	
	$4/MCF[b]		$6/MCF		$10/MCF			
	CON[c]	UNCON[d]	CON	UNCON	CON	UNCON	Accessibility to Pipelines[e]	Blanket Sands Technology Adaptability[f]
Niobrara, Niobrara and Carlile Formations	9.04	9.47	9.38	10.55	9.38	10.55	B	A
All other NGP Formations	56.28	59.94	67.14	79.28	71.70	86.48	C	B
Northern Great Plains/ Williston Basin Region Total	65.32	69.41	76.52	89.83	81.08	97.03		
Uinta	4.14	4.20	4.28	4.46	4.48	4.78	A	B
Piceance Creek	2.10	2.10	3.03	3.61	3.03	3.61	A	B
Greater Green River	2.09	2.09	8.40	8.58	9.62	10.10	A	B
Wind River	0.89	0.97	1.11	1.38	1.16	1.55	B	B
Denver	-	-	-	-	-	-	A	A
Rocky Mountain Region Total	9.22	9.36	16.82	18.03	18.29	20.04		
Cotton Valley	5.39	5.39	6.52	7.11	6.98	8.35	A	A
Edwards Lime Trend	2.15	2.35	6.22	7.01	6.71	8.06	A	B
San Juan	0.46	0.46	1.49	1.49	1.49	1.49	A	A
Val Verde (Ozona & Sonora)	-	-	0.79	1.64	0.84	1.98	A	B
Southwest Region Total	8.00	8.20	15.02	17.25	16.02	19.88		
Grand Total	82.54	86.97	108.36	125.11	115.39	136.95		

[a]The tabular results include only basins and subbasins appraised in detail by NPC. Only undiscovered tight sands gas was appraised in the NPC study. Also excluded are substantial proved reserves in the Denver, San Juan and Cotton Valley Basins.

[b]Mid-year 1981 dollars.

[c]Constrained Well Spacing Case, 4 Wells/Section.

[d]Unconstrained Well Spacing Case, Maximum Recoverable Resource.

[e]Pipeline Accessibility Key: A = Readily accessible or minor linkages required, B = linkages required, C = Unaccessible without substantial development.

[f]Blanket Technology Adaptability Key: A = Technology adaptable with minimal difficulty, B = Geologic problems may prolong the adaptation of the technology.

near-term development based on the factors considered in this study. The San Juan Basin has favorable development potential using a recompletion technology, but does not have a substantial quantity of undiscovered recoverable resource that was appraised by NPC.

CONCLUSIONS

In addition to the results and conclusions described above and presented in the report, two final points should be emphasized:

- *Profits are available in the exploration and development of blanket tight sands gas resources.* For example, if one expects a real wellhead gas price of $3.50 and extraction costs are $2.50, then some additional income is generated. The additional income is shared by the producer, royalty holder and taxing agencies. The producers' share of this income is reported as profits in the year that the gas is produced and, hence, does not represent present value profits at the time of initial exploratory drilling. The present value of profits depends on the production profile from the field, the net revenue stream and the discount rate. Of course risks are present, and profits cannot be guaranteed, but extraction costs are computed to include a compensation for the producer taking risks.

- *The development of blanket tight sands gas can potentially lower gas rates to consumers.* Substantial resources appear to be available in the $2 to $3 range. When this resource is included in energy sector analyses and forecasts over the next 10 to 20 years, market gas prices, and hence the rates consumers need to pay, may be reduced.

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1 INTRODUCTION

The amount of potentially recoverable tight sands gas in the lower 48 states is estimated to be almost equal to the recoverable conventional gas yet to be discovered. There are 20 major 'tight sands' basins located in the Western United States that contain large quantities of natural gas. These basins stretch from New Mexico northward into Canada and eastward into Arkansas and Louisiana. Western tight sands gas is found primarily in sandstone rock formations that have low natural flow properties. The high resistance to gas flow, a principal characteristic of tight sands basins, poses some particular recovery problems that have required the further development of well stimulation and extraction techniques. Nevertheless, tight sands gas is still generally recognized as the best prospect for near-term development among the four major sources of unconventional gas: Devonian shale, methane from coal seams, methane from geopressurized aquifers and tight sands gas.

Several major assessments of these unconventional gas sources have been undertaken.[1-5] Although these studies often differ in their assumptions and appraised geographical areas, their findings suggest that approximately 600 trillion cubic feet (TCF) of tight sands gas could be recoverable. Further, these assessments concur that significant quantities of gas could be extracted from tight gas sands in the near term, if needed.

The Gas Research Institute (GRI), in collaboration with industry, is encouraging the commercial development of tight sands gas both as a near-term and long-term gas supply source. Some tight sands gas is already profitable at current market prices, and has been a source of current gas production.* Research and development (R&D) programs supported by GRI, government and industry will lead to cost reductions in locating and developing tight sands gas and, hence, will further increase its relative attractiveness. These R&D programs are also expected to make available large additional supplies of tight sands gas, which are currently uneconomical.

1.1 CHARACTERISTICS OF TIGHT SANDS GAS

A tight gas deposit is most often defined by its low <u>in situ</u> gas permeability. The petroleum industry generally considers a gas reservoir to be "tight" if its gas permeability is less than 1 millidarcy (md). Conventional gas reservoirs, in contrast, have higher permeabilities. Permeability is a measure of gas flow properties in the formation, where successively larger (smaller) values equate to proportionately greater gas flow (resistance). This correlation between permeability and gas flow properties relates directly to the production economics and commercialization potential of tight sands gas.

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*The Department of Energy estimates that current annual tight sands gas production is more than 1.0 TCF per year, which is about 5% of total U.S. gas

The Federal Energy Regulatory Commission (FERC) has established specific economic incentives for this unconventional gas source. These price incentives are defined in Section 107 of the Natural Gas Policy Act of 1978 (NGPA). In order for tight sands gas to qualify as Section 107 gas, and thereby receive the incentive-pricing pursuant to the Act, the estimated average in situ permeability must be 0.1 md or less.* Thus, FERC explicitly defines tight sands gas as that found in formations with an average in situ permeability level (defined hereafter as k) of 0.1 millidarcy or less.

As previously indicated, the low natural flow rate of a tight gas deposit corresponds to its low in situ gas permeability. Tight gas sands formations that have a low natural flow rate require artificial fracturing -- and most often hydraulic fracturing -- to be used in order to increase the rate of well production, and often to enhance the ultimate recovery from the well. Technology advances in the effectiveness and reliability of hydraulic fractures are a current emphasis of R&D in order to increase potential production from tight sands formations.

Permeability is only one of several geologic and reservoir properties that make up a tight sands gas formation, as well as impose a limit on the amount of commercial gas that can be recovered from the basin. Other characteristics include rock porosity, water saturation, formation type/shape and the presence of clays.** Rock porosity indicates the ability of the tight sands reservoir to contain a significant volume of gas. Porosity is the fraction of the reservoir volume composed of channels and pores. However, the presence of water in the tight sands formation can (1) reduce the amount of space available for the gas by filling the channels and pores with water, and (2) impede gas flow within the formation. Water saturation can thereby be a problem since water can occupy from 25% to 75% of the pore space in the formation. Hence, gas-filled porosity may be considerably less than total rock porosity. This reservoir property is important because the quantity of tight sands gas is typically estimated from gas-filled porosity, formation net pay thickness and the areal extent of the gas-bearing sands.

Another way to classify tight sands gas formations is by shape. There are two general formation types, with various gradations in between. Tight sands gas may be found either in continuous stratigraphic formations called blanket sands, or in discontinuous lense shaped deposits of fluvial origin referred to as lenticular sands. Blanket sands consist of massive, more or less homogeneous sand bodies of uniform thickness and considerable areal extent. Lenticular formations consist of relatively thick sections of shale

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*A more complete description of the regulations and compliance requirements for tight sands gas is found in Sec. 7.

**Certain types of clays have been found to swell when contacted by drilling or fracturing fluids unless the fluids contain chemical agents designed to inhibit swelling.

and clay strata with multiple lenses interspersed throughout the section, as in the nonmarine formations of the Rocky Mountain basins. The multiple lenses can be made up of sandy zones or lenticular sandstone members. There may be some geologic structural control, such as a moderate dome or fault trapping, in both of these formation types. In fact, these areas are often sought out for their gas potential. However, structural control plays a much less important role than in conventional gas reservoirs.

1.2 STUDY OBJECTIVES

The purpose of this study is to assess the quantity of western tight sands gas from blanket formations that is available at competitive extraction costs. To accomplish this purpose four major tasks were defined. These tasks are summarized below:

- address the near-term potential of blanket tight sands gas subject to a variety of economic assumptions.
- determine the effects of technology improvements on the enlargement of the gas supply and the reduction in gas cost.
- express the economically recoverable resource supply in the form of marginal cost curves.
- identify barriers to blanket tight sands gas development and selectively evaluate their effects on near-term development potential.

1.3 METHODOLOGY OVERVIEW

As indicated above, the principal thrust of this study is to identify and assess the near-term potential of gas -- at competitive extraction costs -- from western tight blanket sands. Before the study methodology is described, an explanation is given for the inclusion of only blanket formation tight sands gas.*

The predominant reason for including only blanket formation tight sands gas in this study is that, in most cases, blanket sands are more attractive for near-term development than lenticular sands. To economically develop

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*Tight sands gas studies that have been performed in the past have not sufficiently distinguished between the economics of blanket and lenticular sands. Such a distinction is important because there exists a qualitative difference between the effectiveness and reliability of fracturing technology when applied to blanket versus lenticular sands.

lenticular deposits it may be necessary to contact one or more lenses remote from the well bore with a hydraulic fracture. This is currently difficult, due to problems in controlling the propagation of a fracture at rock interfaces. Lenticular sands contain much of the tight gas-in-place within the Rocky Mountain region. However, as will be shown in this study, substantial deposits of economically recoverable gas in blanket sands also exist, even in the Rocky Mountains. The technology needed to develop these blanket sand resources currently exists. However, estimated improvements in the technology are anticipated as a result of experience in the field, as well as R&D efforts by the private sector, government, and GRI.

The method used to illustrate the economics of blanket sands gas is the construction of blanket resource supply curves. These curves depict the quantity of recoverable blanket sands gas, measured in trillions of cubic feet, available at or less than a given price.

Figure 1 displays the Argonne methodology to derive the resource supply curves. The flowchart presents the major methodological steps. For each major step the action performed and resulting products are identified. The principal data source used to construct the blanket sands supply curves is the National Petroleum Council (NPC) study on *Tight Gas Reservoirs*.[6] The methodology exhibited in Fig. 1 indicates that the NPC modeling results provided the price and rate of return data necessary to determine extraction costs for each formation in the twelve western basins. These data are transformed through a series of steps into a rank distribution of blanket resource supply according to constant dollar extraction cost grades. This cumulative distribution is equivalent to a resource supply or marginal cost curve (see Sec. 2.4). Using these resource supply curves, desired parameter sensitivity analyses are performed.

The specific activities necessary to satisfy the four tasks defined in the study objectives (Sec. 1.2) are the following:

- Derive and present resource supply curves for the blanket sand tight gas deposits found in the twelve appraised western basins.
- Analyze the effects of the required rate of return on extraction costs.
- Assess the modeling of risks as they affect tight sands gas extraction.
- Determine the effects of improvements in fracturing technology on reducing extraction costs.
- Analyze the effects of learning by which both technology improves and risks decrease.

ACTION: Tabulate NPC Basin Risk Analysis Model Economic Summary Output

RESULT: Rate of return r for each price p in every study area for ranges of permeabilities

↓

ACTION: Interpolate to find the value of p such that $r = \bar{r}$, where $\bar{r}$ is either 10%, 15% or 20%

RESULT: Extraction costs in January 1, 1979 dollars

↓

ACTION: Multiply by 1.327 to convert extraction costs into midyear 1981 dollars (Ovid Baker TSG Cost Index)

RESULT: Extraction costs $c(\bar{r})$ in midyear 1981 dollars

↓

ACTION: Sort resources in order of increasing extraction costs

RESULT: Rank order of blanket resources by extraction costs

↓

ACTION: Calculate cumulative distribution by summing the quantity of resource available at any given price or less

RESULT: Resource supply curve (i.e., marginal cost curve)

↓

ACTION: Perform sensitivity analyses with respect to (1) required rate of return $\bar{r}$, (2) average achieved fracture length, (3) and well spacing regulations

RESULT: Families of marginal cost curves showing shifts due to parameter changes.

Fig. 1 ANL Methodology Flow Chart

- Show the effects of current and alternate well spacing regulations on recoverable blanket tight sands gas, and discuss other regulations that apply to the development of tight sands basins.

- Summarize the near-term availability of tight sands gas in specific western basins considering geology and technology, extraction costs and pipeline accessibility parameters.

Each of the activities listed above are discussed in sequence within the remainder of this report. The methodology and procedure used to perform each activity is included where pertinent.

1.4 DATA BASE AND STUDY CONDITIONS

The primary data source used in this study is the National Petroleum Council, *Tight Gas Reservoirs* report.[6] The NPC Tight Gas Reservoirs Task Group prepared this report. The group consisted of teams of geologists, as well as other individuals, experienced in tight gas sands. These teams assessed the gas potential and resource characteristics for the twelve western basins. The geologic data were analyzed using the Basin Risk Analysis Model, which computed real rates of return on exploratory wildcat prospects for alternative wellhead gas prices. These economic results are sufficient to infer extraction costs. The extraction costs are used to derive the resource supply curves and analyze the economics of blanket tight sands gas in this study.

Argonne computerized a substantial portion of the geologic, reservoir and economic data contained in the NPC study. In the process of constructing this tight sands gas data base, an evaluation and analysis of the NPC assumptions and results was performed.[7] Not only is this evaluation necessary to derive the resource curves presented herein, but it also serves to highlight the NPC assumptions for clear reader interpretation and understanding of the results. These results are the estimates of blanket sands gas extraction costs and it is important for users of these estimates (i.e., industry, government, energy-sector modelers, etc.) to fully understand how they were obtained from the NPC modeling approach and assumptions.

This evaluation has also been a useful step in the ongoing appraisal of tight sands gas potential.* In the process of this evaluation Argonne discussed, with the NPC study team members and GRI staff, aspects of the tight sands gas economic modeling that could be strengthened through further

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*A subsequent tight sands gas study has been undertaken by Lewin & Associates, Inc., for GRI to duplicate the modeling effort performed by the NPC Tight Gas Reservoir Task Group. Their mission is to attempt to replicate the NPC results, and thereafter, update its findings.

research. However, because Argonne's directive was to use the NPC *Tight Gas Reservoirs* results as published, no revisions or modifications were made to the NPC study data. The NPC *Tight Gas Reservoirs* study is reviewed in Appendix A.

There are, however, two exceptions to the Argonne directive presented above. These exceptions correspond to two adjustments made to the NPC *Tight Gas Reservoir* data. The first adjustment, discussed in Sec. 1.3, deals with the inclusion of only appraised blanket sands formation gas found in the western basins; lenticular sands are excluded from consideration in this study. The second major adjustment is the inflation of NPC results to midyear 1981 dollars. This adjustment is desirable because the results of the NPC study are expressed in January 1, 1979, dollars. A tight sands gas composite index for drilling and equipping wells, developed by Ovid Baker of Mobil Research and Development Corporation, is used.[8] This index pertains more explicitly to tight gas sands areas and production depths than other indexes. A further discussion of this index appears in Sec. 2.4.1. It is also assumed, consistent with the 1982 GRI baseline projection, that gas drilling costs remain constant in real terms for the period up to the year 2000.[9] This assumption relates to the expected long term trend in drilling costs, and not to possible year-to-year fluctuations.

Topics not addressed in this report are tight sands reservoir production, demand and market clearing prices. However, a previous analysis performed for GRI did consider the demand conditions and market prices for tight sands gas.[7] References to these findings are made where appropriate. Finally, economic rents are not explicitly computed in this report, although they can be easily derived as the difference between the market price of tight sands gas and the extraction cost, as presented herein (Sec. 3.3).

Again, the intent of this study is to determine the quantity of the blanket tight sands gas resource that is economic under various conditions. The economically available resource is determined without a time dimension. Production rates for this blanket resource stock are not specified. Emphasis is focused on near-term development issues that are captured by

- Assessing costs based on existing extraction technology; although sensitivity analyses to future technology improvements are included, and

- Evaluating barriers/constraints to development such as pipeline accessibility, land use conflicts and well-spacing regulations.

2 RESOURCE AVAILABILITY

In this section the estimated size, location, and general physical and economic characteristics of western tight sands gas basins are described (Secs. 2.1 and 2.2). The resource data used in this report are from the twelve appraised western basins studied in detail by the NPC Task Group in *Tight Gas Reservoirs*. Some of the tight sands gas resource examined by the Task Group are excluded from consideration in this Argonne study. The exclusions to this study are identified and briefly discussed in Sec. 2.3. Finally, blanket resource supply and marginal cost curves are presented and interpreted in Secs. 2.4 and 2.5. For the twelve basins that are appraised and incorporated in this report, the focus is on the determination of extraction costs and the sensitivity of these extraction costs to risk reduction and technical progress.

2.1 TIGHT SANDS GAS RESOURCE BASE

There are twenty major western 'tight sands' basins with large amounts of natural gas that stretch from New Mexico northward into Canada, and eastward into Arkansas and Louisiana. The location of these tight sands gas deposits have been known for over thirty years yet, until recently, this resource has not been developed. There are only a handful of basins with a relatively long exploration history. These basins have undergone various levels of development during the last ten years. Drilling and development has occurred in many other tight sands gas areas as well. However, most these other deposits were quickly described as noncommercial with the existing technology and economic conditions, and furthermore, have suffered from an absence of available geologic and resource data relative to conventional oil and gas fields.

Many of the tight sands gas basins cover large land areas where exploration data are often limited, and hence, produce resource estimates that vary widely. Estimates of gas-in-place are as high as 1200 TCF and estimates of recoverable gas range from 25 (for a single basin) to greater than 600 TCF (for a group of basins). Table 1 identifies some of the earlier, and still widely referenced, estimates of potential tight sands gas resources. The earliest study in that group was an extensive assessment prepared in 1973 by the Supply-Technical Advisory Task Force on Natural Gas Technology, as part of the Federal Power Commission (FPC) National Gas Survey.[1] This Task Force conveyed quite an optimistic picture of the tight sands gas resource. They estimated that 600 TCF of tight sands gas could be found in three western basins: Green River, Wyoming (240 TCF); Piceance, Colorado (210 TCF); and Uinta, Utah (150 TCF). These resources were assumed to be quite concentrated with densities up to 340 billion cubic feet (BCF) per sq. mi. An important contribution of this Task Force was to suggest that a feasible and economic extraction technology would be to apply hydraulic fracturing on a massive

Table 1 Estimates of Potential U.S. Tight Sands Gas Resources

Year	Source	Basin/Province	Gas-in-Place (TCF)
1973	U.S. Federal Power Commission (Ref. 1)	Piceance Green River Uinta	242-600
1978	U.S. Federal Energy Regulatory Commission (FERC) (Ref. 2)	Piceance Green River Uinta	600
		Northern Great Plains	130
		San Juan	63
		TOTAL	793
1978	Lewin/U.S. Dept. of Energy (Ref. 3)	Green River Piceance Uinta Northern Great Plains Williston Big Horn Cotton Valley Denver Douglas Arch Ouachita Mtn. San Juan Sonora Wind River	409

scale. They recommended fracturing using fluid volumes many times greater than was conventional at the time to obtain lengths of 1000 ft or more from the well bore. This approach is called massive hydraulic fracturing (MHF).

In 1978, the Advisory Task Force on Nonconventional Natural Gas Resources for the Federal Energy Regulatory Commission retained the 1973 FPC resource estimates, and added an additional 130 TCF of tight sands gas in the Northern Great Plains Basin, Montana and 63 TCF in the San Juan Basin, New Mexico.[2] The total gas-in-place estimate for all the basins was now 793 TCF.

However, this second Task Force report indicated that the difficulties and costs of extracting this resource are much greater than had been anticipated. For example, test applications of MHF indicated that <u>in situ</u> permeabilities were actually 5 to 10 times lower in Western Rocky Mountain basins than were estimated in the first Task Force report. They also found that water-based fracturing fluids may exacerbate the gas conductivity problem by increasing water saturation or by causing the swelling of clay material, which is commonly present. Further, the Task Force stated that if the resource itself could be characterized better, the prospects for economic development would be greatly improved. They found that it is generally necessary to actually drill, complete and fracture a well before key parameters like gas-filled porosity and permeability could be accurately estimated. More sensitive instrumentation and methods to induce small fractures for measurement purposes, before casing is installed, are now being developed to assist in solving that problem. Finally, the second Task Force found that the MHF technology seemed to be quite reliable in blanket formations, which are continuous gas-filled rock strata. But, in lenticular formations, where many lens-shaped gas deposits are separated by impermeable rock, the MHF technology was less understood and less successful.

The third major study of the tight sands gas resource was performed by Lewin and Associates for the Department of Energy. The Lewin estimate of gas-in-place was 409 TCF for the 13 basins analyzed. Correspondingly, their estimate of recoverable gas ranged from 70 to 188 TCF. Lewin assessed the production potential of the 13 basins under alternative levels of economic incentives and technology improvements. They tested the importance of individual technology improvements on overall performance. Lewin found that the technology improvements with the largest impact on ultimate recovery and net present value include: improved ability to differentiate and characterize the gas reservoirs; capacity to stimulate multiple reservoirs from a common well bore; improved predictability of fracture performance; increased effective propped fracture length; and optimizing field development.[3]

The most current, comprehensive assessment of the tight sands gas resource is the National Petroleum Council (NPC) study on *Tight Gas Reservoirs*.[6] The NPC study is based on a lesser number of basins than the Lewin study, but includes speculative and very tight sandstone not included in the Lewin survey. Further, there are many technical differences and alternative assumptions that distinguish the two studies.[7] The NPC study is described in greater detail below, and in Appendix A.

2.2 NPC TIGHT SANDS GAS RESOURCE BASE FOR TWELVE APPRAISED BASINS

The major basin characteristics and a description of the NPC resource estimates appears in the following subsections. Many of the geologic and resource data assembled by the NPC Task Group have been computerized by Argonne in order to prepare this report. This data base is described in Appendix B.

2.2.1 Basin Characteristics of NPC Appraised Areas

NPC appraised twelve western tight sands gas basins in detail. These basins are shown geographically in Fig. 2, and listed by region in Table 2. This table also shows the total recoverable gas (both blanket and lenticular), the maximum blanket recoverable gas and the percent blanket gas. In terms of area, measured in sections (mi^2), the Northern Great Plains is by far the largest appraised basin. Note that the resource density, measured in BCF of gas per section, varies widely from 1.9 in the appraised area in the San Juan basin to 19.2 in Edwards Lime Trend. Depth and drilling cost also vary widely from 2000-foot wells costing $100,000 in Northern Great Plains to 13,000-foot wells costing $2.8 million in Edwards Lime Trend.*

2.2.2 Summary of NPC Tight Sands Gas Resource Estimates

The tight sands gas resource estimates from the NPC study are summarized in Table 3. NPC estimates that the maximum recoverable gas from tight sands formations in the lower 48 states is about 600 TCF. Of this total, 365 TCF is economically recoverable at $6.64 per thousand cubic feet (MCF) (constant midyear 1981 dollars) with a real rate of return of at least 15%. However, only 165 TCF is in the twelve NPC appraised basins. Recall that in this report, blanket sands gas is separated from lenticular sands gas. Subsequently, it is estimated herein that 111 TCF of blanket gas resource is recoverable at $6.64/MCF, with a 15% real rate of return and the well-spacing constraint of 4 wells per section. The blanket gas resource is 67% of the estimate of total economically recoverable gas.

In the NPC economic analysis, typical current well-spacing regulations were incorporated. Specifically, a maximum of four wells per section were allowed. However, in the long run these regulations may be relaxed for tight sands gas formations. It is estimated herein that 131 TCF would be economically recoverable at $6.64/MCF and a 15% rate of return, if the well-spacing regulation were removed. This topic is discussed in detail in Sec. 7.

It is important to remember in reading this report that most of the blanket gas in the twelve appraised basins is found in the Northern Great Plains. Further, for this region, 100% of the gas potential area was appraised. This is not the case for all other basins.

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*A detailed description and characterization of the NPC tight sands gas basins was prepared by Argonne to support its economic evaluation of the resource.[7] Geologic characteristics of each basin, together with basin-specific cost and production data, were compiled. These data were extracted, summarized and interpretated from the NPC study and other sources to identify only the salient facts.

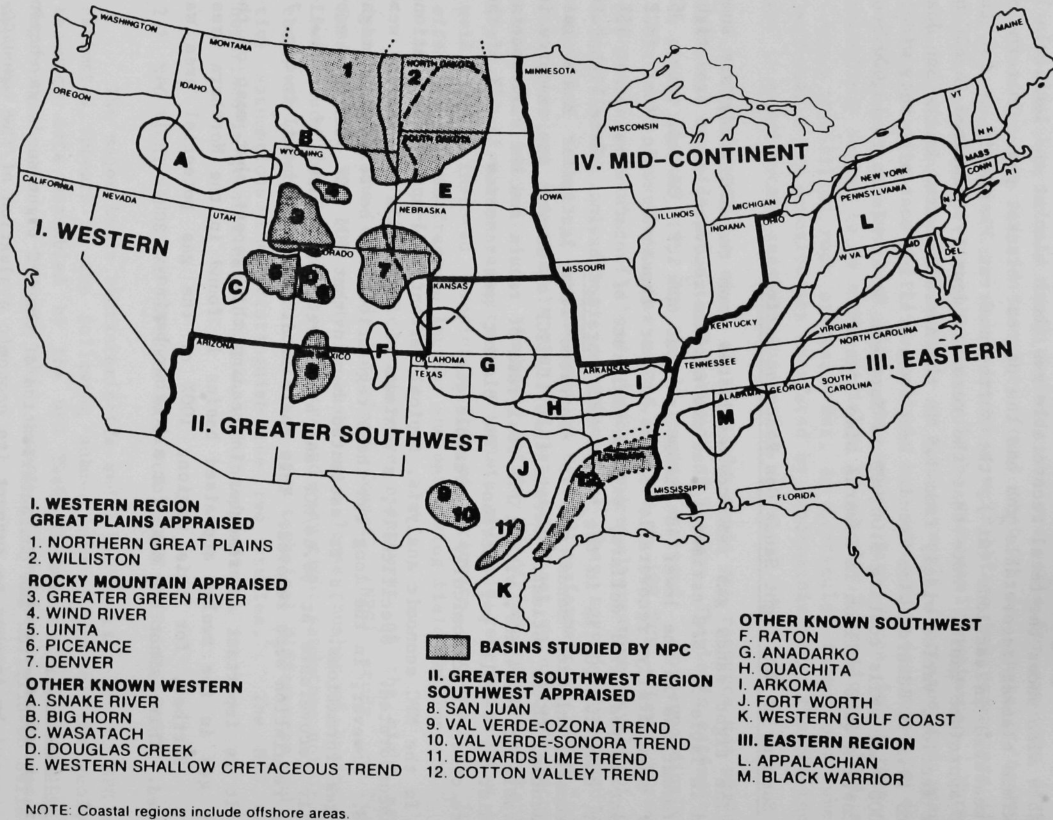

Fig. 2 Tight Sands Gas Basin Map (Source: Ref. 6)

Table 2 Summary of Selected Western Tight Sands Basin Characteristics

Regions/Basins	Maximum Recoverable Gas (MRG)[a] (TCF)	Maximum Blanket Formation Recoverable Gas (MRG) (TCF)	Percent Blanket (%)	Sections of Probable Tight Gas Production (Mi^2)	MRG/Productive Sections (Bcf/Mi^2)	Average Depth[b] (Ft.)	Average Well Cost[b] (Thousands of Midyear 1981$)
Northern Great Plains							
Northern Great Plains/Williston	100.2	100.2	100.0	32,730	3.1	2,000	100
Region Total	100.2	100.2	100.0				
Rocky Mountains							
Uinta	15.3	4.3	28.2	1,184	12.9	7,700	754
Piceance Creek	33.0	3.7	11.2	3,144	10.5	8,050	703
Greater Green River	86.5	12.6	14.6	8,938	9.7	10,700	1,504
Wind River	23.3	1.5	6.6	2,280	10.2	10,700	1,802
Denver	7.9	7.9	100.0	1,600	4.9	8,000	602
Region Total	166.0	30.0	18.1				
Southwest							
Cotton Valley	12.8	12.8	100.0	1,027	12.5	9,000	800
Edwards Lime Trend	8.6	8.6	100.0	450	19.2	13,200	2,805
San Juan	2.2	2.2	100.0	1,188	1.9	7,150	1,352
Val Verde (Ozona & Sonora)	2.8	2.8	100.0	500	5.6	6,900	276
Region Total	26.4	26.4	100.0				

[a]Includes only basins or sub-basins appraised in detail by NPC. Only unproven tight sands gas was appraised. As of January 1979, 11 TCF of additional tight sands gas was classified as proven among the 12 basins, and thereby omitted from the NPC study. (By region, these proven reserves are distributed accordingly: Southwest 7 TCF; Rocky Mountains 3 TCF; Northern Great Plains 1 TCF estimated by American Gas Association (AGA) from AGA proved reserves as of December 31, 1979).[10] These proven reserves are principally in the Cotton Valley, San Juan and Denver basins.

[b]Weighted Average Using MRG as Weights.

Source: NPC, *Tight Gas Reservoirs*, Vol. V (Ref. 6).

Table 3 U.S. Tight Sands Gas Resource and Recovery Estimates (TCF) Appraised and Extrapolated Areas (Lower 48 States)

Resource Categories	Appraised (12 Basins)	Extrapolated (101 Basins)	Total[a]
Prospective Area (Sections)	359,500	655,000	1,014,500
Productive Area (Sections)	53,000	68,500	121,500
Total Gas in Place (TCF)	444	480	924
Maximum Recoverable Gas (TCF)	293	315	608
Economically Recoverable Gas (TCF) @ $6.64/MCF in 1981 dollars (i.e., $5.00 in Jan. 1979 dollars) 15% real rate of return			
Lenticular and Blanket	165	200	365
Blanket	111		
Blanket without well-spacing constraint	131		

[a]Totals may not add due to rounding.

Source: NPC, *Tight Gas Reservoirs*, Vol. V (Ref. 6) and Argonne study data.

In the Rocky Mountain region most of the tight gas sands are lenticular. However, this report shows substantial quantities of blanket sands gas resources in the Rocky Mountain region also. Almost all of the tight sands gas resource was appraised in this region. In the "Other Western" extrapolated area, an estimated 10 TCF of blanket sands gas was not appraised in detail (see Sec. 2.3.1). Regarding the development of this resource, it should be noted that some lenticular gas sands that contact a well bore can be fractured and produced simultaneously with a blanket formation above or below the pay zone.[11] Finally, some lenticular resource formations in the Rocky Mountain region are less difficult to develop than others.

The Southwest tight sands gas resource is all blanket, although Sonora in the Val Verde Basin may be considered very large lenses. It is important not to be misled in this report by the relatively small amount of tight sands gas reported in the Southwest. The reason for this is that the appraised area was only a small percentage of the total gas potential area. A comparison is shown in Table 4. Specifically, the appraised area was estimated to contain less than 20% of the recoverable tight sands gas in the Southwest region.

Table 4 Comparison of Appraised and Extrapolated Blanket Tight Sands Gas in the Southwest

Categories of Gas	Prospective Area (sections)	Productive Area (sections)	Estimated Gas-in-Place (TCF)	Maximum Rec. Gas (TCF)	Economically Rec. Gas[a] (TCF)
SOUTHWEST Appraised Areas	73,000	3,200	44	26	15.4
SOUTHWEST Extrapolated	330,000	17,500	184	113	69.4
Total Southwest	403,000	20,700	228	139	84.8
Appraised as percent of total	22.1	15.5	19.3	18.7	18.2

[a]Conditions: $6.64 in midyear 1981 dollars ($5.00 in Jan. 1979 dollars); 15% real rate of return; Constrained case with a maximum of 4 wells/section.

2.3 TIGHT SANDS RESOURCES EXCLUDED FROM THIS STUDY

In order to properly interpret the results presented in this report, it is important to keep in mind what resources are excluded. These are briefly discussed below.

2.3.1 Extrapolated Areas

The NPC Task Group appraised in detail 35% of the area in the lower 48 states known to contain natural gas. The results were then extrapolated to the remaining areas. The extrapolated area is divided into four regions: Other Southwest, Other Western, Eastern and Mid-Continent. These extrapolated regions were further disaggregated by type of formation. Gas-in-place was estimated by type of formation. Then the amount of gas economically recoverable at various prices was estimated by comparing the extrapolated formations with similar formations in the twelve basins appraised in detail.

2.3.2 Lenticular Sands

Table 2 clearly shows that only the Rocky Mountain region contains any lenticular sands resource appraised by the NPC Task Force. In developing these lenticular deposits it is desirable to be able to contact, with a fracture, one or more lenses remote from the well bore. This is currently difficult, due to problems in controlling the propagation of a fracture at a rock interface. Because of technological and risk uncertainties, lenticular sands deposits were excluded from consideration in this near-term tight sands gas report.

However, it should be noted that some lenticular formations in the Rocky Mountain Basin are less difficult to develop than others. The Ericson formation in Greater Green River has lenses separated by sandstone instead of shale. The interfaces between types of rock in this formation are less severe than most lenticular formations. For Ericson, a fracture may be able to propagate in a predictable manner with a good chance of contacting additional lenses away from the well bore.

2.3.3 Already Discovered Tight Sands Gas

So far it has been emphasized that this report excludes tight sands gas from lenticular formations and NPC extrapolated areas. The NPC study focused on assessing only the undiscovered gas potential. However, substantial known reserves of tight sands gas exist today. These reserves are also excluded from this report. As a result, basins which are commonly considered good tight sands gas areas may not appear as attractive when only their undiscovered gas potential is considered. Specifically, the Wattenberg field in the Denver Basin has produced substantial amounts of tight sands gas. Also there is considerable activity in the tight formations in Cotton Valley, Texas and San Juan, New Mexico.

2.3.4 Tight Sands Zone Recompletions

Finally, an attractive development approach to known tight gas sands reserves is the recompletion of existing gas wells in tight gas zones. There is a very large recompletion potential in the San Juan Basin. This approach is discussed more fully in the NPC report.[6]

2.4 BLANKET RESOURCE SUPPLY CURVES

The previous subsections have discussed the tight sands gas resource base, the recoverable resource appraised by NPC and the tight sands resources excluded from this study. In the following subsection, the recoverable blanket sands gas resource will be presented in the form of resource supply curves -- quantity available at given price levels. Only blanket resource supply curves are derived from the NPC resource data for the twelve appraised western basins. Argonne transformed the raw resource data into resource supply curves (i.e., marginal cost curves) according to the procedure described in Appendix B, and updated the extraction cost data to midyear 1981 dollars through use of the Ovid Baker composite cost index. A flow chart depicting the data transformation procedures used to obtain the resource supply curves is presented in Fig. 1 of Sec. 1.3. Section 2.4.1 describes the extraction cost updating procedures and the composite index used. The final subsection (Sec. 2.4.2) presents the regional resource supply curves and discusses their proper interpretation and potential applications.

2.4.1 Baker Composite Index for Drilling and Equipping Tight Sands Gas Wells

The extraction cost data contained in the NPC report correspond to January 1, 1979 costs. To update these data to current dollars and, thereby, enhance the usefulness of the marginal cost curves and analyses derived from these data, a cost escalation procedure was employed. A midyear 1981 base period was selected to express the cost data because it coincides with the initial preparation of this report. Data from this period were the most accurate available. The midyear 1981 costs were obtained from the NPC January 1, 1979 costs by applying a composite index for drilling and equipping wells developed by Ovid Baker, of Mobil Research and Development Corporation.[8]

During the 30-month period between January 1979 and July 1981, the Baker index rose 32.7%. Other indexes, including the Independent Petroleum Association of America (IPAA) composite index could be used to update the extraction costs. However, the Baker index was selected because its geographical and technical basis corresponds more closely with the tight sands basin characteristics. If other indexes are preferred to perform this cost escalation procedure, the vertical axis of the resource supply curve could simply be scaled by a constant percentage.

Ovid Baker, the chairman of the *Tight Gas Reservoir* Task Group, compiled the index subsequent to the release of the NPC report. The foundation of his index is the IPAA composite index for drilling and equipping wells.[12] In order to arrive at a tight sands gas index he segregated the IPAA data according to two variables: depth and region. By performing this process, the derived-IPAA index conforms to geographical areas and drilling depths that better represent current tight sands gas activity. The Baker index for tight sands gas drilling costs "was based on drilling costs per foot in the depth range of 7,500 to 9,999 ft. This is the depth of many tight gas reservoirs. These costs per foot were taken from the states of Colorado, New Mexico, Texas District 6, Utah and Wyoming where much of the tight gas resource is located".[8]

2.4.2 Interpretation and Use of the Blanket Resource Supply Curves

Blanket resource supply curves are shown in Fig. 3 by region. This figure presents the NPC Base Case with a 15% real rate of return and 1000-ft average fracture length. Also included in the NPC Base Case is a well spacing constraint that allows a maximum of four wells per section. The vertical (y) axis is the extraction cost in constant midyear 1981 dollars per MCF. The definition and meaning of extraction cost will be discussed in Sec. 3.

The vertical axis can also be considered the minimum acceptable price to cover exploration, development and production costs, as well as taxes and royalty, for the undiscovered tight sands gas. The horizontal (x) axis is the cumulative economically recoverable blanket resource. At higher prices, the amount of economically recoverable blanket resource increases. The use of the

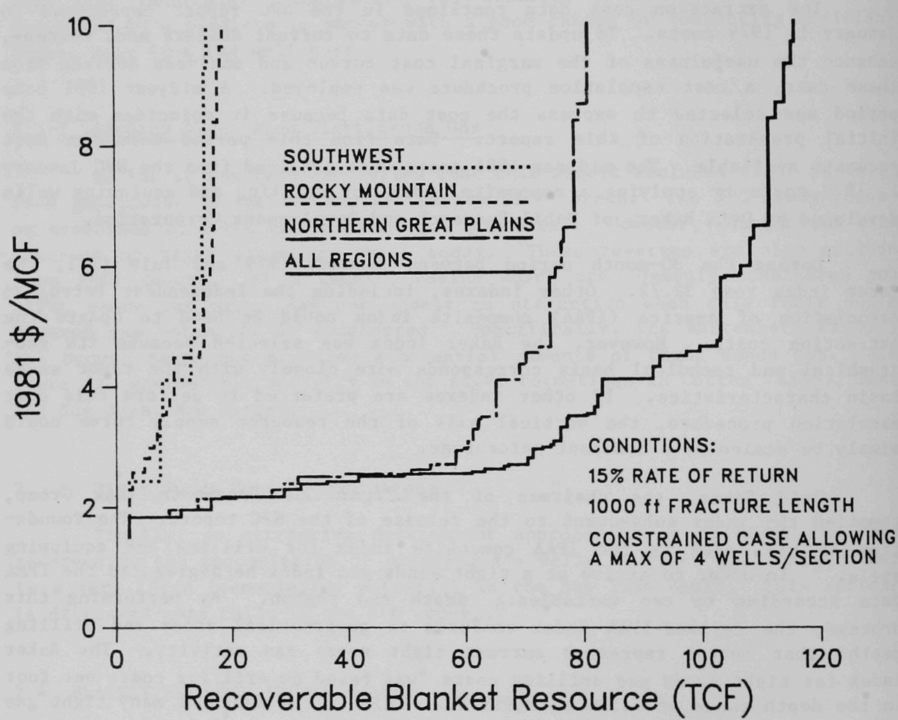

Fig. 3 Blanket Resource Supply Curves by Region

resource supply curves can be illustrated with an example. Suppose the wellhead price for tight sands gas in constant midyear 1981 dollars is $5.00/MCF.* The blanket resource supply curves in Fig. 3 show that 103 TCF of gas is economically recoverable in all twelve appraised basins at $5.00/MCF. By region, 74.5 TCF is economic in Northern Great Plains, 15.0 TCF is economic in Rocky Mountains and 13.5 TCF is economic in the Southwest. In reviewing these numbers, it is important to remember that less than 20% of the undiscovered gas potential was appraised in the Southwest.

Note that the resource supply curves appear to have a staircase pattern. Each horizontal step is the quantity of blanket tight sands gas recoverable at the exact extraction cost shown on the y-axis. Vertical movements along the the curve indicate that no additional resource is becoming economic for small price increases. When the price rises to the point where more resource does become economic, there is a horizontal jump by the amount of the additional resource. Since the estimation of extraction costs is not precise, the staircase resource supply curves could be replaced by smoothed versions, if desired. This is not done here.

Resource supply curves are quite useful in assessing the quantities of resource available at a given price. This type of supply curve is often used formally in energy sector forecasting models.

It is important to remember, however, that the resource supply curves presented here have important exclusions. Less than 20% of the blanket tight sands gas in the Southwest is included here. Also substantial blanket resources in the Eastern and Midcontinent regions are totally excluded.

2.5 MARGINAL COST CURVES

Resource supply curves like those shown in Fig. 3 can be considered to be marginal cost curves. The assumption is that the resource is depleted in the order of cost grades, starting with the lowest cost grades first. Then the cost of one additional unit of resource is given by the resource supply curve based on the amount of previous cumulative production. Again it should be emphasized that this interpretation is based on the assumption that the resource is systematically developed across basins and subbasin locations in order to extract the next least cost remaining resource. No provision is made for producing simultaneously from a distribution of resource cost grades.

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*Actually, the maximum lawful price under the NGPA of 1978 for tight formation gas was $5.444/MCF in January 1983. This price can be considered a constant dollar price because it is allowed to increase at the rate of inflation (plus a small adjustment).

3 EXTRACTION COST

The main issue in developing western tight sands gas is economics. Hence, it is important to assess the costs of finding and developing tight sands gas fields. This section will discuss the concepts and summarize the methodology to arrive at blanket sands extraction costs. The following section (Sec. 4) will present results and interpretations.

3.1 DEFINITION OF EXTRACTION COST

In this subsection the determination of tight sands gas extraction costs is discussed. It is desired that the form of extraction costs be on a dollar per MCF ($/MCF) basis. Several complications arise in defining extraction cost:

- Costs are incurred in all three phases of extraction: exploration, field development and production.
- Indirect overhead costs, taxes, royalty and leasehold costs are present.
- Large risks exist in gas exploration and significant risks exist in field development and marketing.
- Typically, cost outlays precede the generation of revenues. That is, expenditures are not well "matched" to the production of gas.
- Costs and prices are projected to increase over time due to inflation.

It is necessary that extraction costs take all these issues into account. First, extraction costs must cover exploration costs and risk as well as development and production costs. Otherwise, one would underestimate the required incentive necessary to find natural gas and hence, to replace reserves as they are depleted. To deal with this issue, the basic unit for economic analysis is taken to be the prospect, i.e., a potential new field wildcat drilling location.

Second, extraction costs should be sufficient to cover geologic appraisal of the prospect, taxes, royalty, leasehold and overhead costs, as well as costs for drilling, equipping, fracturing, operating and maintaining wells.

Third, the presence of risk implies probability distributions of outcomes for costs and revenues. The probability distributions may be fairly well known in a mature gas play. In relatively unexplored basins, judgmental or subjective probabilities may be used, based on available geologic data. Possible risks for tight sands gas extraction are discussed in Sec. 4.

Fourth, the timing delay between the up-front investments and gas production is handled using standard financial methods. In particular, the internal rate of return on the average after-tax cash flow stream is computed. The averaging takes place over the outcomes in each prospect. The internal rate of return is the discount rate which results in a zero net present value for the after-tax cash flow. Compensation for risk may be reflected in a higher required rate of return, a topic which is discussed in Sec. 4.

Finally, in this report inflation is neglected by expressing all costs and prices in real terms. NPC used January 1, 1979 dollars as the base year. Argonne escalated the base year to midyear 1981 using the Ovid Baker index for drilling and equipping wells (Sec. 2.4.1).

There is a useful definition of extraction cost which takes all the above considerations into account:

> *Extraction cost is defined as the price per MCF, constant over time in real terms, such that the resulting average after-tax cash flow per prospect exhibits just the required rate of return.*

Of course, extraction costs based on the above broad definition also depend on technical details like the treatment of federal and state taxes.

Hence, extraction costs can be viewed as a minimum required price to induce exploration, not including Hotelling rents. Hotelling rents are discussed in Sec. 3.3. Further, extraction costs are equivalent to levelized constant dollar gas costs. Levelized constant dollar gas cost is the price of gas, constant in real terms over time, such that the resulting revenues (i.e., revenue requirements) just equal the discounted present value of costs, including taxes. In fact, this relationship between revenue requirements and present value costs is exploited in Sec. 6.2 in order to obtain new extraction costs due to technology advancement. The equivalence of (1) extraction costs, as defined here, (2) levelized constant dollar gas costs and (3) minimum required gas price may be useful in comparing alternative sources of gas on a unit cost basis.

3.2 BASIN RISK ANALYSIS MODEL (NPC)

Extraction costs, as defined here, are consistent with the economic results reported in the NPC *Tight Gas Reservoirs* study.[6] The NPC study used a Monte Carlo simulation model called the Basin Risk Analysis Model. The methodology incorporated in this model is summarized below. A more detailed discussion of the assumptions underlying the NPC study appears in Appendix A.

In the NPC study, the basic unit of analysis is the prospect. One or two wildcat wells are drilled in a prospect. Each prospect is assumed to have a single average permeability or k-level. The probability of finding any particular k-level is specified for each subbasin study area. Whether the wildcat is successful or dry is also described by probabilities. Wildcats that discover gas in k-levels that are not economic (at a given price and discount rate) are considered dry wells. A successful wildcat results in a tight gas field capable of being developed.

Field size is also given by a probability distribution, which depends on the basin and k-level. Given a field size, sufficient development wells are drilled to deplete the field, assuming wells produce for thirty years. Larger fields are developed over a greater number of years. There is a 20% dry hole rate for development wells. Moreover, in the NPC Base Case a maximum of four wells per section is allowed. When this constraint binds, the recoverable gas from the field is reduced.

In summary, analyzing a prospect amounts to observing the outcomes of random selections for wildcat success, k-level and field size. Associated with each random outcome is a time path of cost outlays including the drilling, fracturing, maintaining and operating of wells. Also, there will be a time path of gas production. A well production decline curve is associated with each k-level by study area. One-eighth of gas production is required for the royalty.

Suppose the producer's share of the gas is sold at a price p which is constant over time in real terms. Then the time path of after-tax net profits can be determined for each randomly selected prospect. In the NPC analysis eight values of p were used: 1.50, 2.50, 3.10, 3.50, 5.00, 7.00, 9.00, and 12.00 in January 1, 1979 dollars. For each p, one thousand prospects were analyzed. The results vary for each prospect due to different random outcomes. However, after 1000 samples, the average after-tax profit stream tends to stabilize. For each p, the internal rate of return r is computed for this average after-tax profit stream.

In this Argonne study, the NPC results relating p and the internal rate of return r are used to obtain extraction costs. Note that r will always be an increasing function of p. Suppose that $\bar{r}$ is the rate of return necessary to cover the real cost of capital for the firm plus the additional return on risk that may be required. As defined previously, the value of p just sufficient to yield a rate of return of $\bar{r}$ is the extraction cost, denoted by $c(\bar{r})$. The value of p which just yields $\bar{r}$ can be obtained by interpolating between the specific prices which are analyzed in the NPC study. The interpolation procedure is illustrated in Appendix B.

In Sec. 4, the resulting extraction costs, obtained by interpolating the NPC economic results, are presented in the form of marginal cost curves for the blanket tight sands resource. These marginal cost curves are shown for $\bar{r}$ = 10%, 15% and 20%.

3.3 RESOURCE PRODUCTION AND THE HOTELLING THEORY

Extraction costs, as defined previously, represent the price which just covers exploration, development and production expenditures using a discount rate $\bar{r}$. That is, the extraction cost is the break-even price such that the net present value of the average after-tax profit flow is zero. Hence, for any market price p above the extraction cost, the net present value is positive. Then on the average, additional profits are earned in the business of wildcat exploration. Of course, this is a risky business with a range of outcomes. Even though the average situation shows profits, this will not be true in every case.

It is obvious that the time at which resources will be produced is related to their profitability. The formal economic theory based on this relationship was first proposed by economist Harold Hotelling in 1931.[13] Hotelling postulated that firms choose when to develop resources based upon profit maximization. He asked the question, what is the optimal timing of production to maximize profits? Hotelling was able to solve this problem for simple cases.

The Hotelling theory is based heavily on the difference between market price at the wellhead and unit extraction cost. This difference is illustrated in Fig. 4 for a wellhead price assumed to be $4.00.* The solution to the Hotelling problem depends on how this difference between price and cost evolves over time. Prices may be expected to change due to changing market conditions or resource depletion. Costs may shift downward over time due to technical progress. The effects of technology on reducing unit extraction costs will be shown in Sec. 6.

The existence of many different cost grades giving rise to an upward sloping marginal cost curve, as shown in Fig. 4, is important for the Hotelling theory. The details have been calculated in a separate paper.[14] It is fair to say that the Hotelling theory has given rise to a whole new field of economics. Much literature is accumulating in this field of resource economics.

The Hotelling theory is analytically pleasing, but empirically some difficulties arise. The Hotelling theory would seem to imply that resources are developed sequentially, strictly in order of cost, with the lowest cost grade first. However, empirically some mixture of cost grades appear to be developed simultaneously. Reasons for this may include locational preferences of drillers, desire by a land owner to develop his land or just random elements.

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*The blanket resource supply curve has the following conditions: constrained well spacing case, 15% rate of return, 1000-ft fracture length, and total appraised blanket supply for 12 NPC basins.

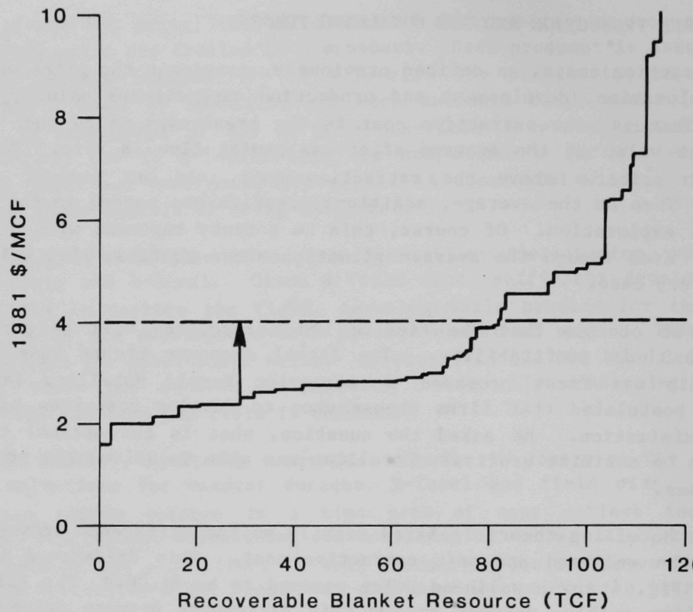


Fig. 4 Illustration of Hotelling Theory for a $4.00/MCF Market Clearing Price

4 MARGINAL COST CURVE RESULTS AND INTERPRETATION OF THE RISK PREMIUM

In Sec. 2.4 the blanket resource supply curve (i.e., marginal cost curve) was presented for a required 15% real rate of return. In this section, the sensitivity of the blanket resource supply curve to the required rate of return is analyzed. Three marginal cost curves are presented to correspond with a 10%, 15% and 20% rate of return. Each marginal cost curve is developed using the methodology described in Sec. 3.

A high required rate of return indicates either that the opportunity cost of capital is high, or the risk premium is high, or both. Risks associated with tight sands gas extraction, as well as the concept of risk premium, are discussed later in this section.

4.1 SENSITIVITY TO THE REQUIRED RATE OF RETURN

The blanket resource supply curves are shown in Fig. 5. The relative positions of these resource supply curves indicate that extraction costs are significantly lower (higher) when the required rate of return is reduced (increased). Consider, for example, the minimum acceptable price required to make 50 TCF of blanket tight sands gas economical. This can be determined from Fig. 5 for the twelve appraised blanket sands basins. At a 15% real rate of return, the extraction cost of the last unit produced is $2.55/MCF. When the risk is higher, at a 20% real rate of return, the extraction cost increases to $3.17/MCF. When the risk is lower, corresponding to a real rate of return of 10%, the extraction cost decreases to $1.85/MCF.

Table 5 presents summary results in the form of average percent change between two resource supply curves with different required rates of return. This is computed by integrating the percent change between the two curves. When the required real rate of return is reduced from 20% to 15%, average extraction costs drop 20.4%. Reducing the required return further from 15% to 10% causes extraction costs to decrease 24.6%. The elasticities, taking into account the percent changes in the rate of return, are 0.82 and 0.74 respectively. Elasticities give the average percent change in extraction cost for a 1% change in the rate of return. Note that the change from 15% to 10% rate of return has a larger absolute effect on the percent change in extraction costs, but the elasticity is less compared with the change from 20% to 15% in the rate of return.

Table 5 also has results for individual regions. Extraction costs in the Rocky Mountains and the Southwest are slightly less sensitive in percentage terms to the required rate of return than Northern Great Plains.

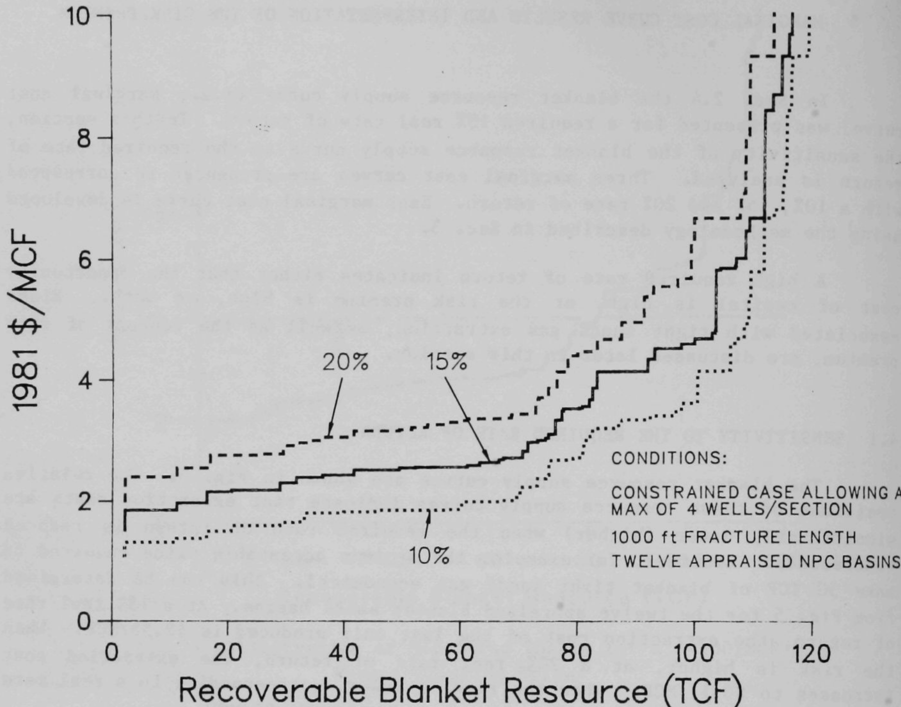


Fig. 5 Sensitivity of Extraction Costs to Required Rate of Return

4.2 RISK ANALYSIS

Risk is defined as the possible variability in the actual rate of return around the expected return. Some risks associated with developing the tight sands gas resource are common to the petroleum industry generally. Other risks correspond specifically to tight gas. Risks apply to both blanket and lenticular formations within the tight sands resource, although the technical risks for the discontinuous lenticular deposits are considerably more serious. The following statement summarizes some of the risks that were addressed in the NPC study:

> Exploration and development of tight gas resources involve risk and uncertainty. The usual surface exploration methods are of little value in locating a well because the gas does not exist in conventional, structural traps and there is little physical difference between "dry" and "productive" areas. Once a productive formation has been drilled, its

Table 5 Percent Change in Extraction Costs and Corresponding Elasticities[a] for Incremental Reductions in the Required Rate of Return[b]

Change in Required Rate of Return	Regions			
	All	Northern Great Plains	Rocky Mountains	Southwest
20% → 15%	20.4 (.82)	21.1 (.84)	18.7 (.75)	18.6 (.75)
15% → 10%	24.6 (.74)	25.7 (.77)	21.5 (.64)	23.0 (.69)

[a]Elasticities presented in parentheses ( ).

[b]Conditions: 1000-ft fracture length and constrained resource case (i.e., limit of 4 wells/section).

> production rate must be increased by stimulation (usually massive hydraulic fracturing [MHF]). Risk and uncertainty can be reduced by improving reservoir characterization techniques and by increasing the reliability and efficiency of massive hydraulic fracturing. Such improvements in fracturing techniques are required for the adequate development of lenticular formations which contain more than 40% of the recoverable tight gas resource. Also, a productive area may be abandoned if the gas sales price is too low to provide an adequate return on investment. The percentage of prospects that are profitable increases significantly at the higher gas prices examined, reducing the risk of a productive area being abandoned.*

The discussion in this section will be mostly qualitative. That is, no attempt will be made to estimate whether the required risk-adjusted real return on tight sands gas is, say, 10% or 20%. However, some quantitative methods like the Capital Asset Pricing Model (CAPM) may be useful tools. Risk premiums are discussed in Sec. 4.5.

In this section, types of risk affecting tight sands gas development are classified as commercial, technical, geologic, and regulatory/political.

*Ref. 6, p.3.

Risks can also be classified as systematic and diversifiable. This distinction will be discussed in Sec. 4.5.1.

4.2.1 Commercial Risks

Commercial risks pertain to the market for tight sands gas. The demand for natural gas and fuel price projections will not be discussed here. However, it might be noted that tight sands gas development may be exposed to commercial risk somewhat more than conventional gas. The reason is that conventional gas wells tend to produce sooner having higher overall rates of decline in production, and hence faster paybacks, than tight sands gas wells. Tight sands gas wells exhibit an initial steep decline but then have a more stable production, which declines only slowly over many years. If the economic assessment is based on, say, a 30-year production period, the return on tight sands gas investments will be more sensitive to events further in the future. This increases commercial risk.

Available capacity in existing pipelines and the construction of new pipelines into remote tight sands basins, such as the Northern Great Plains and Rocky Mountains, may also be viewed as a form of commercial risk.

4.2.2 Technical Risks

Many of the tight sands gas formations exist at depths that range from 10,000 ft to 15,000 ft. Technically, it is difficult to drill at these depths. Also, many tight sands basins contain multiple overlapping formations with gas potential. In addition, a single formation could contain several tight gas sand layers. Simultaneous massive hydraulic fracturing of multiple layers is difficult to control.* Instead of simultaneous fracturing, distinct MHF jobs on separate layers (possibly with multiple well completions) are still difficult, expensive and risky. Risks associated with fracture reliability and efficiency will be discussed further in Sec. 5.2.3.

4.2.3 Geologic Risks

Geologic risks pertain to the location and properties of tight sand gas deposits. There is uncertainty regarding <u>in situ</u> permeability k, net pay thickness h, gas-filled porosity ϕ, field size, depth and rock properties. Of course, it is desirable to discover sweet spots with high values for kh. Some geologic risks average out, provided sufficient wells are drilled. However, before a large scale drilling program begins, even the probability distributions regarding tight sands gas characteristics are not known well. Hence,

*The technical literature is abundant with examples documenting this problem. See Society of Petroleum Engineers Journals and Symposium Proceedings.

there is uncertainty in how much resource is actually available and its respective characteristics.

4.2.4 Regulatory/Political Risk

Historically, the natural gas industry has been affected by various regulations such as the Natural Gas Policy Act wellhead pricing incentives, well-spacing regulations and various forms of taxation. Possible future changes in these types of regulations represent risks to the investor in tight sands gas production.

4.3 ORGANIZATION OF THE INDUSTRY

The exposure to risk does depend on the type of firm. Major oil companies can better average risks over many exploratory wells. Independent companies, which do much of the exploration for tight sands gas, control risks by forming limited partnerships and retaining only a small fraction of the venture. Historically, some regulated affiliates of gas pipeline companies have produced and sold gas on a cost-of-service basis, which reduces the risk of recovering costs.

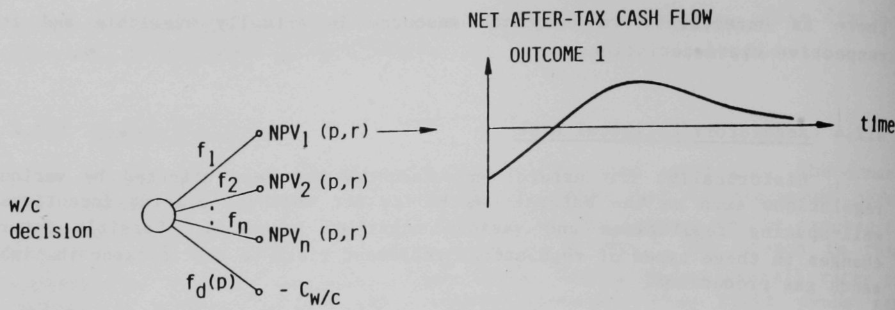
4.4 DECISION TREE FORMULATION

In this subsection, the risks discussed previously will be represented in a simple decision tree. The solution to the decision tree, with the inclusion of risk premiums, will be discussed in the next subsection.

A simple decision tree for a wildcat well is illustrated in Fig. 6. In the NPC analysis, the basic unit of analysis is the prospect. A prospect is a wildcat location in which one or possibly two wildcat wells may be drilled. The possibility of a second wildcat is neglected here for convenience.

In the decision tree, the probability $f_d(p)$ is the chance of having a dry wildcat well. Whether marginal wells are classified as dry will depend on the price p. Dry hole costs are denoted by $c_{w/c}$. Let 1, ..., n be the set of outcomes for which a gas field is discovered and developed. In theory the set of outcomes is very large, comprising any combination of possibilities for geologic, technical, commercial or regulatory risk.

In addition to dry hole risk, the two other kinds of risk considered in the NPC study were k-level and field size. For the NPC study, then, the list of outcomes is the set of possible combinations of k-levels and field sizes that are economic. The f_i is the probability of the i^{th} combination of k-level and field size. Incidently, these are not independent variables, since field size does depend on k-level. Therefore, f_i represents the joint probabilities that could be specified analytically, or generated from



$$EV = \sum_{i=1}^{n} f_i \, NPV_i (p,r) - f_d(p) \, C_{W/C}$$

Fig. 6 Wildcat Drilling Decision Tree with Alternative Cash Flow Outcomes

frequency distributions by repeated random sampling. The NPC study used the repeated random sampling (Monte Carlo) approach. Beyond the NPC study, other random variables that could also be considered are total resource size in a subbasin study area and net pay thickness.

Regarding technological risk, instead of only considering well performance, with a 1000-ft average achieved fracture length, a range of fracture efficiencies could be considered directly. A distribution of achieved fracture length could be specified. Various outcomes could also be specified regarding commercial and regulatory risk.

For the risk-neutral investor, it may make little difference whether average risk values are used in the analysis, when compared with the alternative of explicitly considering the full distribution of values. However, with risk aversion some form of correction for the variability in outcomes is appropriate. This is discussed in the next section.

4.5 RISK PREMIUM

Risk premiums are difficult to measure. However, considerable indirect evidence indicates that they exist. For example, recently the *Oil and Gas Journal* commented on the payout time for tight sands gas wells. It stated "Payout times vary, but several producers cite 2-4 years. Without higher prices, some wells would take 8 years to pay out and therefore wouldn't be drilled."[15]

One quantitative attempt at measuring risk premiums is the Capital Asset Pricing Model.

4.5.1 Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) is the leading method to represent risk in modern corporate finance.[16] The model states that there is a linear relationship between the quantity of risk and the required risk premium (called the market line). The CAPM is based on modern portfolio theory under which all nonsystematic risks can be diversified away. Hence, only systematic or market risk matters. The measure of this risk is the beta (β) coefficient. Empirically, β's are estimated by correlating the historical returns on the investment with market return generally. The cost-of-equity-capital is then given by the sum of a risk-free rate of return plus a risk premium proportional to β. For $\beta = 1$, the cost-of-equity is the expected future market return. In a recent paper, the cost-of-equity for domestic oil companies was estimated to be 20.4% in nominal terms, and 17.6% for international oil companies.[17] These rates might be considered appropriate discount rates for evaluating an energy project, if the investment had the same risks as the industry as a whole. Many of the risks associated with tight sands gas are common to those of the oil and gas industry generally.

However, it has been suggested by Basil Kalymon that for large energy investments both systematic and nonsystematic risks may be important.[18] In his article the author first shows how systematic risks in the oil and gas industry arise through linkages between energy prices, and economic activity and growth. This finding coincides with the CAPM theory where only systematic risks affect the risk premium and required rate of return. However, Kalymon then suggests that if total risks are large enough, nonsystematic risks may also affect the required rate of return on large energy investments.

4.5.2 Types of Risk Premiums

The most common approach to incorporate a risk premium is to increase the required return on the investment $\bar{r}$. In the decision tree described earlier, this process amounts to discounting the net after-tax cash flow for each outcome at a rate which includes the risk premium. The higher the risk premium, the lower the net present value $NPV_i(p,\bar{r})$ associated with outcome i, as illustrated in Fig. 6.

The $NPV_i(p,\bar{r})$ depends on price p for each outcome i. A higher price increases revenues and net cash flow. The expected value EV of the decision tree is shown in Fig. 6. The extraction cost $c(\bar{r})$ has been defined as the value of p such that the expected value EV of the decision tree is zero, given a discount rate of $\bar{r}$.

An alternative way to incorporate a risk premium is as follows: separate out geologic exploration risks associated with wildcat decisions from commercial and technical risks, which apply to all drilling, including development wells. This process should yield a lower discount rate applicable to field development, once the geologic outcome is known from the wildcat well drilling and fracturing activity. Again, this situation can be illustrated by Fig. 6. Let outcome i represent the geologic outcome obtained from drilling and fracturing the wildcat. The $NPV_i(p,\bar{r})$ associated with development and production can then be calculated using a lower discount rate $\bar{r}$, since *ex post*, the geologic outcome is better known (for good or for worse), and the risk is reduced. As a result of a lower $\bar{r}$, the $NPV_i(p,\bar{r})$ is larger. Then the expected value EV associated with the wildcat decision tree increases when a lower discount rate $\bar{r}$ is used. Let p* be the price just required to induce the drilling of a wildcat well. Suppose the expected value EV, given price p*, is positive. That is, surplus value is anticipated in the field development and gas production phases. This surplus value associated with field development, and the resulting positive *required* EV associated with drilling the wildcat, is another form of risk premium. The required value can be derived if the utility function of the risk-averse decision maker is known. The decision maker is presumed to maximize expected utility.

In summary, risks tend to increase extraction costs. One mechanism for this relationship is to include a risk premium in the required rate of return $\bar{r}$ (or discount rate). Another mechanism is to discount at the risk-free rate of time preference, but to maximize the expected utility of a risk-averse decision maker. Both methods have advantages and disadvantages. For example, optimizing field development and making marginal well development decisions are appropriately based on lower discount rates, since at that point exploration risks are equivalent to sunk costs.

In any case, extraction costs must be sufficient to cover exploration, as well as development and production costs for tight sands gas. Further, the costs necessary to cover exploration include compensation for risk. Professors Millsaps and Ott state, in their paper on risk aversion and oil exploration state that, "To the extent that risk is inherent in this environment, it is in effect a cost of production."[19]

5 DESCRIPTION OF EXTRACTION TECHNOLOGY

Much of the technology needed to extract tight sands gas is common to other activities in the petroleum industry. These technologies often include drilling technology for deep, high-pressure formations; lift equipment for liquids; and compression for use in shallow formations. Two types of technology, however, are particularly important in the development of the tight sands gas resource: massive hydraulic fracturing (MHF) and measurement of reservoir properties and fracture characteristics. This section discusses both of these technologies but, as will be indicated, greater attention is devoted to a description of MHF and its performance characteristics. Other forms of extraction techniques that have been applied to tight formations, such as chemical or nuclear explosive fracturing, will not be discussed.

5.1 TIGHT SANDS GAS RESOURCE MEASUREMENT

Measurement of the reservoir properties and fracture characteristics of a tight sands formation is an important stage in (1) the determination of the resource base and its physical and geologic parameters, and (2) the calibration of reservoir simulation models. Measurement technologies that are used to detect the resource and to measure the reservoir parameters include core samples, gamma ray logs, spontaneous potential (SP) logs and pressure transient tests. Fracture height at the well bore can be assessed using temperature decay profiles or radioactivity techniques.

Measurement problems associated with tight gas sands are presently very difficult, and are an area of current R&D. Since direct measurement with instrumentation is very difficult, indirect methods of estimating reservoir parameters (e.g., permeability) using simulation models and history matching are used. The technologies to measure reservoir properties and fracture characteristics are not addressed in this report.

5.2 MASSIVE HYDRAULIC FRACTURING

The hydraulic fracturing process dates back to 1947 when the first field test was conducted in Kansas.[20] But it was not until 1973 that the Supply-Technical Advisory Task Force on Natural Gas Technology assessed the application of hydraulic fracturing to tight gas formations as part of the Federal Power Comission National Gas Survey.[1] The Task Force suggested that tight sands gas could be economically extracted by applying hydraulic fracturing on a scale several times greater than that previously practiced in conventional reservoir fracturing. This "extended" hydraulic fracturing technique is referred to as massive hydraulic fracturing. Massive fractures, with an effective length of 1000 to 1500 ft, as well as moderate fractures, with an effective length of 200 to 500 ft, are in current use. The optimum fracture treatment design depends on the formation conditions. Some of the most important aspects of fracture design and the effects of fracture treatments on well performance are discussed in the following subsections.

5.2.1 Hydraulic Fracture Treatment Description

Generally, a hydraulic fracture treatment consists of pumping fluids down the borehole at a sufficient rate of flow and pressure in order to fracture the rock formation containing the natural gas. The process of hydraulic fracturing is designed to increase the productivity of the well by enlarging the surface area of the formation that is in direct contact with the borehole (i.e., create channels of greater permeability than the formation itself so that gas from a larger area in the formation could be released and flow at a higher rate through this new fracture to the borehole). The desired result of a hydraulic fracture treatment is a vertical fracture in the formation that is perpendicular to the borehole and extends outward in opposite directions to lengths sometimes greater than 1500 ft. However, because in situ stresses exist in the formation, there is a strong tendency for the rock to 'heal' or close up around the fracture. This begins to occur when the pressure created by the hydraulic pumping and fracture fluids is relieved. To counteract complete fracture closure, it is a common practice to mix solid particles, called proppants, into the fracturing fluid. The proppants are designed to be carried by the fracture fluid into the fracture and deposited along the new fracture faces once the pressure is relieved and the fracture begins to close. The proppants prevent the fracture from 'healing' completely because they 'prop open' the hydraulically created fracture. If the hydraulic fracture treatment is properly designed and executed, the proppants are fairly evenly distributed along the two faces of the newly created fracture. In a successful treatment, an avenue or channel is created by the deposited proppant through which gas can flow at a greater rate from the formation pores to the borehole. The enhanced gas flow resulting from a hydraulic fracture treatment is created by the permeability of the proppant pack being greater than that of the surrounding rock formations. The tight sands gas migrates to these areas of higher permeability from the lower permeability, tight sands pores where the gas is trapped. Therefore, through hydraulic fracture treatment applications to tight gas sands, an avenue or channel is created for enhanced gas flow and production by (1) creating a fracture that directly links a larger area of the formation to the borehole and (2) the deposition of a proppant along the fracture faces that has a greater permeability than the tight sands formation and thereby induces the outflow of gas from the formation pores and into the fracture channel.

5.2.2 Fracture Design Parameters and Modeling

The previous section (Sec. 5.2.1) described the hydraulic fracturing process. In this subsection some of the principal parameters of a hydraulic fracture treatment are discussed. A summary of the fracture process appears first to introduce some technical terms and concepts.

The hydraulic fracture treatment consists of first injecting a clear fracture fluid (also often referred to as frac fluid) into the tight sands formation. This clear fluid is called a pad volume. Following this initial pad volume, a proppant is blended into the frac fluid and transported by the fluid into the fracture. Finally, the frac fluid is pumped out of the well, leaving the proppant to hold open the hydraulically created fracture. The initial pad volume allows for the possibility of some fluid leakoff to occur, without the deposition of the proppant in areas that might cause production problems, i.e., around the borehole. This is a major problem affecting fracture reliability and predictability (Sec. 5.2.3).

There are many types of fracture fluids used by industry. These include water, brines, gelled hydrocarbons, emulsions and other aqueous solutions. The choice of frac fluid depends on reservoir conditions, and the kinds of rocks and clays present. Fluid loss into the formation is a problem. The amount of leak off depends on the permeability and compressibility of the formation, as well as the viscosity of the frac fluid and the chemical additives used.* The most commonly used proppant is sand, although bauxite is often used for deeper tight sands formations.

Fractures generally have a vertical orientation and propagate outward in opposite directions from the well bore. Horizontal or "pancake" fractures are thought to have been created in shallow, low-pressure formations, but these are rare. There are generally three distinctions made about the length of the hydraulically created fracture, along with its measurement. First, <u>fracture length</u> refers to the half-length outward from the well bore in either direction. Second, <u>hydraulic length</u> is the distance from the well bore to the tip of the created fracture. Third, the <u>achieved propped length</u> (or effective length) is the distance that remains held open by the proppant once the fluid is removed. A sketch of typical fracture geometry is illustrated in Fig. 7.

The design parameters for a fracture are the volume of frac fluid, the proppant weight, the types of materials and additives used, the injection rate of the fracture fluid and the schedule of these injections. Fracture height h is often controlled by barrier formations bounding the tight sands formation being fractured. However, penetration into the barrier rock can cause a number of problems. The probability of breaking through the barrier rock can be reduced by altering the viscosity of the frac fluid, but this may, in turn, cause a reduction in effective proppant transport.[21]

Two types of fracture propagation models are commonly used for fracture design by major oil companies and well service companies. The models are used to estimate fracture width and length. The Perkins-Kern model postulates

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*Frac fluid additives can create a "filter cake" or a wall along the fractured rock surface, reducing leak off. Additives are also commonly mixed with the frac fluid to counteract geologic conditions, such as the rock-swelling nature of clays in the presence of a water-based fracture fluids.

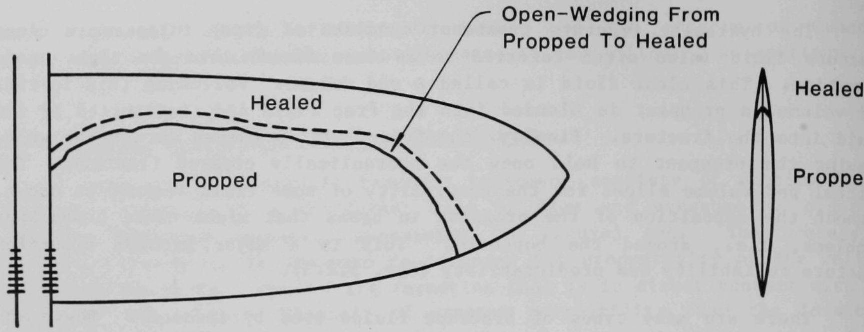

Fig. 7 Example of Created and Propped Fracture Geometry [Source: Veatch, Ralph W., Jr., Current Hydraulic Fracturing Treatment and Design Technology (Ref. 20)]

elliptical cross sections in both the horizontal and vertical planes. Alternatively, the Geertsma-DeKlerk model is ellipical in the horizontal plane but rectangular in the vertical plane.[22] According to a review by R. Veatch, "widths calculated from the Perkins-Kern model are generally smaller than those computed by the Geertsma-DeKlerk model and hence the Perkins-Kern results will predict a significantly longer fracture length for a given amount of injected fluid at a given rate, all other parameters being the same."[20] The two models have other differences in their implications. According to the Perkins-Kern model, fracturing pressures increase with fracture length, but according to the Geertsma-DeKlerk model the inverse relationship is predicted. It is thought that the Geertsma-DeKlerk model is applicable to situations where vertical height is about the same as length.

5.2.3 Fracture Reliability and Distribution of Performance

It is now common for 1000-ft propped fracture lengths to be achieved in practice. However, there are difficulties in consistently (i.e., reliably) achieving a 1000-ft propped fracture. These problems arise particularly during the learning phase of the developing of a new formation or basin. Some of these problems are identified in a subsequent paragraph.

In practice, fracture and well performance vary, even to the extent that fractures sometimes fail altogether. This variability results in a distribution of fracture and well performance, since a formation (or basin) will generate a variety of fracture length outcomes, even from identical fracture treatment designs.* In the NPC study, the Task Group used an average

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*See Sec. 5.2.4 for a summary of some industry data on well performance experience.

effective fracture length value of 1000 ft, instead of a distribution of values in their analysis. This 1000-ft fracture length is the Task Group's assessment of the current average effective fracture length being achieved in industry practice.

In addition to the achieved propped fracture length, fracture conductivity, defined as fracture permeability k_f times fracture width w, is important in determining well performance.

There are several ways in which average effective fracture length can be increased. One way is to improve fracture efficiency. Currently, the achieved propped length is about 60% to 70% of the created hydraulic length.[23] Technology advancements may be able to achieve 80% of the created hydraulic length, and also attain a greater degree of control over the propagation and dimensions of a fracture. In addition, average fracture performance can also increase through continued improvements in reliability. For this to happen the kinds of problems discussed below will have to be minimized.

J.K. Thompson lists several reasons why well performance in an area may tend to fall below that predicted:[24]

- incorrect estimate of effective formation permeability
- propped fracture height considerably less than formation thickness
- proppant crushing
- proppant embedment in the formation restricting gas flow
- other types of fracture damage
- post-frac damage to the formation
- irregular proppant settling
- geologically discontinuous sands
- mechanical problems with the completion or treatment itself

Some of the problems identified above can create a condition referred to as "screen-out". The term "screen-out" refers to a premature termination of a hydraulic fracture operation.[25] This situation arises when there is excessive pressure build-up due to blockage by the proppant. Formation screen-outs are caused by excessive frac fluid leakoff depositing almost dry proppant, concentrated to the point where blockage results. Well bore screen-outs also can happen, but these have become less common.

In lenticular formations additional problems occur. Impermeable shales typically separate the gas-bearing rock. Fracture propagation across these rock interfaces is difficult to achieve.

In summary, the distribution of achieved fracture lengths - from the longest to the shortest fracture - is important in evaluations of fracture and well performance. One reason this distribution is important is for computing the mean effective fracture length for use in technology assessments and capital investment decisions. The second reason is that fracture reliability is determined from this distribution of achieved fracture lengths: the narrower the distribution the less risk and the more accurate will be the prediction of average achieved fracture length.

5.2.4 Empirical Estimates of Average Fracture and Well Performance

This section reviews the empirical evidence that has been used to estimate the historic, mean effective fracture length. An industry data base gathered by Lee and Holditch is the principal source used to identify the mean effective fracture length that was predominant in the latter part of the 1970s.

Several papers in the literature present examples of fracture and well peformance. In particular, a paper by Lee and Holditch presents data from thirteen wells fractured during the period 1973 to 1979 (with a mean of 1977).[23] Six wells were in limestone formations, representative of three different areas in Texas. Seven wells were in sandstone formations in Texas, Louisiana and Canada. Effective reservoir permeability and achieved propped fracture length were estimated by history matching, based on pressure transient build-up data and well production. In the Lee-Holditch paper, fracture height, designed propped length, achieved propped length and frac fluid volume are presented. This sample of data, although small and possibly somewhat limited, does provide some insight into average fractured well performances for that period in the mid to late seventies. For fracture jobs which appeared successful, the ratio of achieved propped length to design propped length had an average of 68.4%. However, three wells performed substantially below expectations, probably indicating poor sand transport. The average ratio, including wells that did not perform up to expectations, was 56.4%. Since the period when these wells were fractured, there has been considerable advancement in the technology so that these ratios have improved.

These data were analyzed further by Argonne.[26] Instead of relating achieved fracture length to design fracture length, achieved fracture length was related to fracture fluid volume. The advantage of the Argonne approach is that volume is a directly measurable quantity. The need to estimate design propped length based on volume and other parameters is eliminated. It is suspected that fracture length, width and height all increase somewhat with fracture volumes, except in cases where barrier rocks above and below a formation determine fracture height. Hence, one would expect that the dimensions of the fracture could be approximately related to a power function of volume (i.e., V^{α}). In the analysis relating achieved propped length to volume, the exponent was estimated to be 0.64. This provides some insight into the rate at which height versus width increases as a function of fracture fluid volume. Although other variables are important in the relationship between volume and achieved length, volume alone explains a significant percentage of the variance.

In the NPC study, total fracture cost and volume were taken to be proportional (see Fig. A-1 in Appendix A). That is, the relationship between volume and average fracture length is equivalent to the relationship between total cost and achieved fracture length. Hence, Argonne's investigation of this latter relationship shows the expected value of fracture length for a given cost.

6 EFFECTS OF TECHNOLOGY ADVANCEMENT AND LEARNING ON THE RECOVERABLE BLANKET RESOURCE

Section 5 provided a brief description of the hydraulic fracturing technology, and the factors that influence fracturing effectiveness and reliability. This section presents results that illustrate the sensitivity of extraction costs to hydraulic fracture technology advancement. The minimum undiscounted benefits derived from technology advancement are also presented. Sections 6.1 and 6.2 contain these findings, while Sec. 6.3 displays the effects of learning on the recoverable blanket resource, i.e., risk reduction and technology improvement combined. Finally, Sec. 6.4 presents the methodology employed to compute the extraction costs for alternate technology assumptions. Section 6.4 can be skipped by readers not interested in how the data contained in Secs. 6.1 through 6.3 were derived.

6.1 SENSITIVITY TO AVERAGE FRACTURE PERFORMANCE

A major type of technical progress related to tight gas sands is the improved performance of massive hydraulic fracturing. In this section, the sensitivity of extraction costs to average effective fracture length is investigated. Effective fracture length is defined to be the achieved propped fracture length.

There are several ways in which average effective fracture length can be increased. One way is to improve fracture efficiency. Currently, the achieved propped length is about 60% to 70% of the created hydraulic length.[23] Technology advancements may be able to achieve 80% of the created hydraulic length, and also attain a greater degree of control of the propagation and dimensions of a fracture. In addition, average fracture performance can also increase through continued improvements in reliability. For this to happen the kinds of problems discussed in Sec. 5.2.3, such as screen-outs, poor sand transport and mechanical problems, will have to be minimized.

Based on the Lee-Holditch data from the mid to late seventies, an achieved fracture length between 600 and 800 ft was an appropriate average value that for period given the fracture design parameters from the NPC study.[23] Since that time, however, there have been rapid advances in fracturing technology, and continued progress is expected.

Figure 8 depicts the blanket resource supply curves for a 600-ft and an 800-ft average effective fracture. As indicated by the Lee-Holditch data, among others, this range of average effective fracture lengths was typical in the final years of the last decade. The resource extraction costs for these two fracture lengths are computed using the Argonne methodology described in Sec. 6.4. It is evident from Fig. 8 that extraction costs are quite sensitive to longer achieved propped fracture lengths. However, the relative position of these resource supply curves to one another confirms that, at better

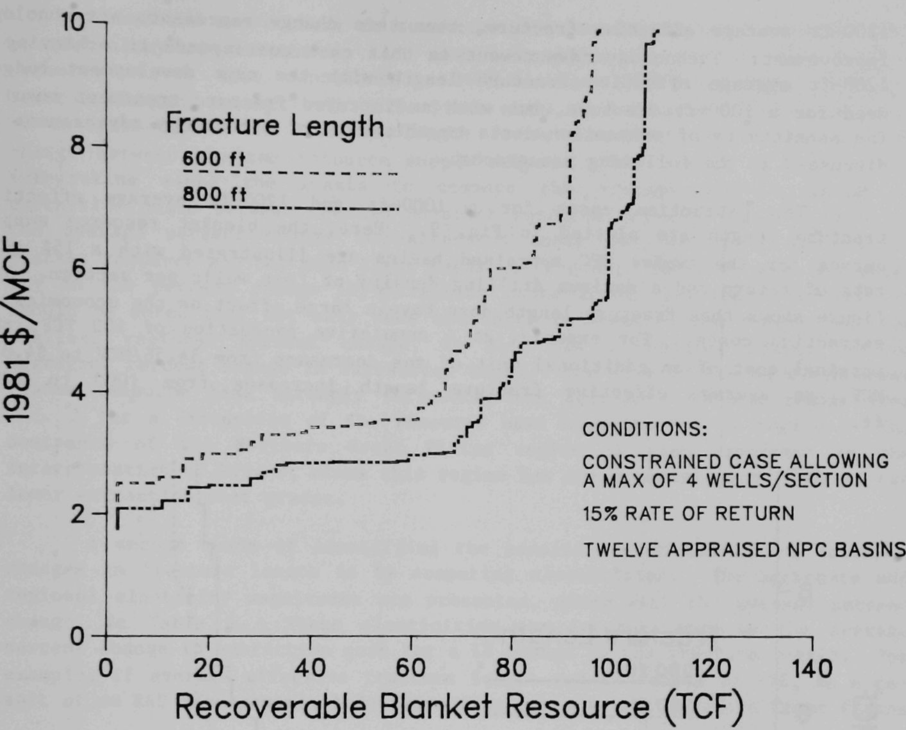

Fig. 8 Blanket Resource Supply Curves Exhibiting the Range of Average Effective Fracture Lengths during the Late 1970s

permeability grades, extraction costs are less sensitive to changes in fracture length, whereas, at poorer permeability grades, with a higher extraction cost, technology progress has more of an effect. For poorer cost grades, a longer fracture length often yields a greater quantity of blanket tight sands gas as well as a lower overall extraction cost. The total net benefit of achieving a greater average achieved propped fracture length is both a greater quantity of blanket tight sands gas as well as a lower extraction cost for each increment of resource that is already economic (see Sec. 6.2).

In the NPC *Tight Gas Reservoirs* study, the Task Force assumed that a 1000-ft achieved fracture length would be realized on average, given a fracture design for a 1700-ft created hydraulic length. Given this fracture design, the Task Force prepared cost estimates of undertaking the hydraulic fracture treatment. Now consider technical progress in fracturing. If the same hydraulic fracturing cost for a 1000-ft propped length can now produce a

1200-ft average effective fracture, then this change represents a technology improvement. Technology advancement in this case corresponds to achieving a 1200-ft average effective fracture length with the same development budget used for a 1000-ft fracture, but with an improved fracture treatment result. The sensitivity of extraction costs to this type of technology advancement is discussed in the following paragraphs.

The extraction costs for a 1000-ft and 1200-ft average effective fracture length are plotted in Fig. 9. Here, the blanket resource supply curves for the twelve NPC appraised basins are illustrated with a 15% real rate of return and a maximum drilling density of four wells per section. The figure shows that fracture length does have a large effect on the economics of extraction costs. For example, at a cumulative production of 100 TCF, the marginal cost of an additional unit of gas decreases from \$4.56/MCF to \$4.01/MCF, as average effective fracture length increases from 1000 to 1200 ft.

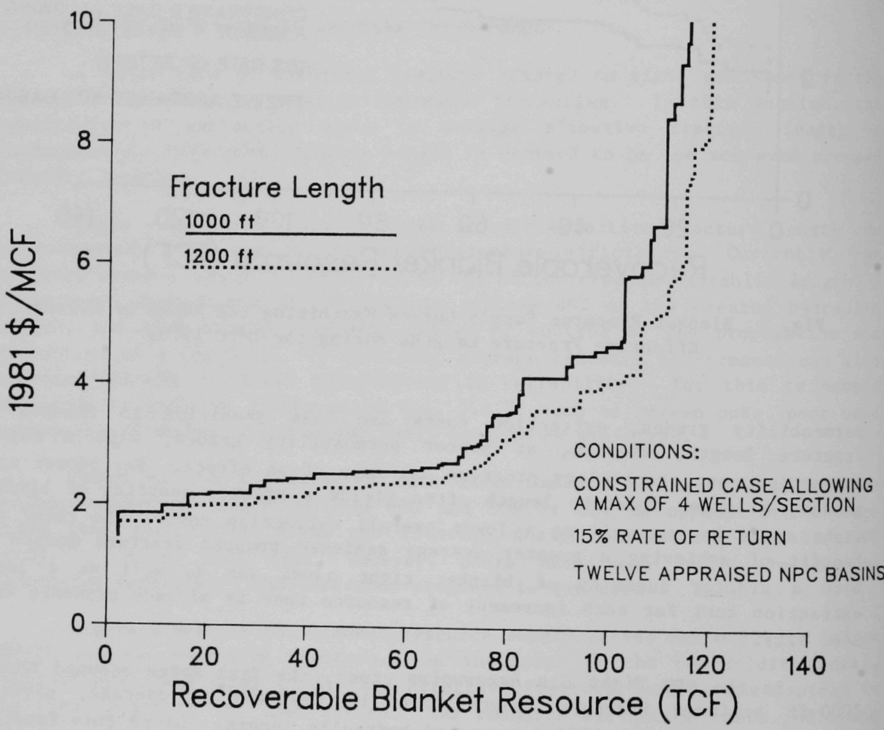

Fig. 9 Sensitivity of Extraction Costs to Achieved Propped Fracture Length

There are two methods to summarize the sensitivity of extraction cost to technology advancements. Each method computes the area between the two resource curves that represents a 1000-ft and 1200-ft average effective fracture length, respectively. The first means of determining the sensitivity of extraction cost to fracture length is by computing the average percent change between the two resource supply curves. This result is obtained by integrating along the x-axis to compute the average percent change in extraction costs between the two adjacent resource curves. Table 6 presents the average percent change in extraction costs for the total recoverable blanket resource and for each tight sands gas region. There is some variability in the percent change in extraction costs across regions. However, it should be noted that not only does the Northern Great Plains region have the smallest regional percent change, it also has a dominant effect on the aggregate percent change in extraction costs. The size of the Northern Great Plains resource base strongly influences the aggregate percent change (see Sec. 2 for a discussion of the resource base distribution by region.) The dominance of the Northern Great Plains region is also important in the interpretation of Fig. 9, since this region has the greatest proportion of the lower extraction cost grades.

A second means of identifying the sensitivity of extraction costs to changes in fracture length is by computing elasticities. The aggregate and regional elasticity magnitudes are presented, along with the average percent change, in Table 6. These elasticities are interpretated as the average percent change in extraction cost for a 1% change in the fracture length. For example, if average effective fracture length was increased by 10%, as a result of an R&D advancement, then extraction costs in the Northern Great Plains

Table 6 Percent Change in Extraction Costs and Corresponding Elasticities for a Change in Effective Fracture Length from 1000 to 1200 ft

Measures of Change	Regions			
	All	Northern Great Plains	Rocky Mountains	Southwest
% Change in Extraction Cost	13.5	12.1	14.6	15.6
Elasticity	0.67	0.60	0.73	0.78

[a]Conditions: 15% rate of return and constrained resource case (i.e., limit of 4 wells/section).

region would decrease by an average of 6%, all other things equal.* A greater decline in extraction costs would occur in the other two regions because, as already indicated, they contain a larger proportion of the lower permeability/higher cost grade resource that is more sensitive to changes in fracture length. In the Rocky Mountain and Southwest regions a 10% change in average effective fracture length would correspond to a 7.3% and 7.8% average reduction in extraction cost, respectively, with all other factors equal. These elasticity magnitudes relate to a change in fracture length from 1000 to 1200 ft. Argonne derived elasticities for each 200-ft increment from a 600-ft to a 1200-ft average effective fracture length. These unpublished results indicate that the aggregate and regional elasticities across fracture length increments are fairly robust: the elasticities are stable and have a small variance. The regional differences in elasticity magnitudes retain their relative relationships.

The added importance of fracture length for the very low permeability/high cost grades is illustrated in Fig. 10. Here, the moving average percent

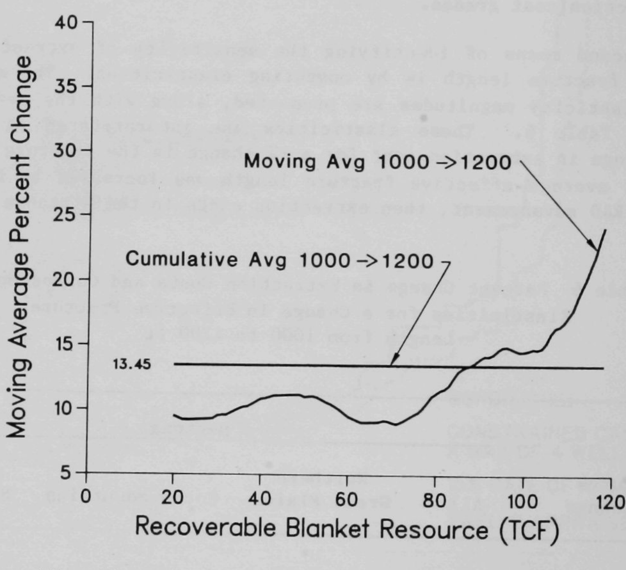

Fig. 10 Relationships between Higher Cost Grade Resources and Sensitivity to Fracture Length

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*Fracture technology advancement in this study corresponds to an increase in average effective fracture length with the same capital development budget but with an improved fracture treatment design that results in greater fracture effectiveness.

change in extraction costs (averaging over 20 TCF intervals) is compared with the total average over the entire curve. The total average value appearing in the figure is the same as that reported in Table 6. Very significant upward trends are seen in Fig. 10. This upward movement eventually contributes to the moving average becoming greater than the total (cumulative) average. Initially, the moving average percent decrease in extraction cost is 9-11% for the lower cost grades. As previously indicated much of the lower cost grade resource is found in the Northern Great Plains region and is not as sensitive to changes in fracture length. In contrast, for the last interval of 20 TCF, the average percent decrease in extraction cost is about 25%. Hence, the very low permeability/high cost grades are relatively more sensitive to fracture length.

By presenting the fracture length sensitivity results in the form of total and moving average percent change it can be concluded that (1) the percent change between the 1000-ft and 1200-ft average effective fracture lengths is greater at the lower permeability/higher cost grades, than at the higher permeability grades, and (2) it is not only more costly to develop the lower permeability grades but the importance of the achieved effective fracture length becomes more significant at these cost grades, since the percent change between the two average fracture lengths increases. Graphically, this effect can be seen more clearly in Fig. 9. Figure 10 merely presents the difference between the 1000-ft and 1200-ft supply curves as a single moving average curve and a total average curve.

6.2 TOTAL UNDISCOUNTED BENEFITS FROM TECHNOLOGY ADVANCEMENT

Section 6.1 presented the sensitivity of extraction costs to average effective fracture length. In this subsection the undiscounted economic benefits resulting from increasing the average effective fracture length from 1000 to 1200 ft are examined.

Figure 11 presents the two resource supply curves corresponding to a 1000-ft and 1200-ft fracture length, respectively. The undiscounted economic value resulting from the technical progress in fracture technology (i.e., increasing the average effective fracture length from 1000 to 1200 ft) is represented in Fig. 11 as total undiscounted benefits. The vertical axis on the right side of the graph shows undiscounted benefits corresponding to alternative market prices. The shaded area between the two curves indicates the undiscounted economic benefits that will accrue if the average effective fracture length is increased by 200 ft. For example, with an extraction cost of \$4.00/MCF or less, the total undiscounted benefits that will be produced from a 200-ft average effective fracture length increase are \$27.4 billion. Correspondingly, for an extraction cost of \$6.00/MCF or less, the total undiscounted benefits from the fracture length change are \$45.1 billion. Finally, at \$10.00/MCF or less the total undiscounted benefits of technology progress are \$67.9 billion.

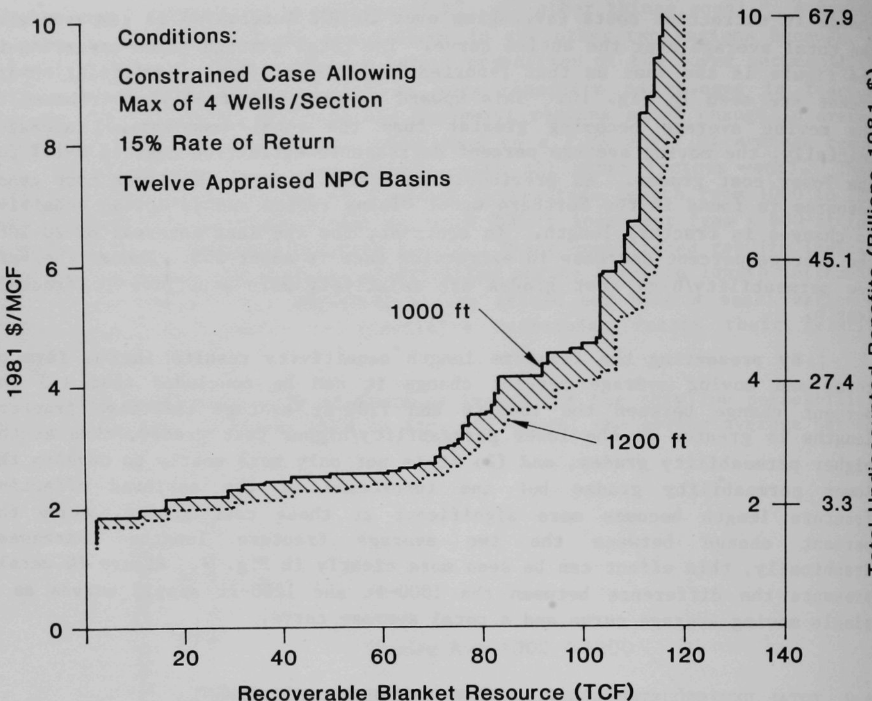

Fig. 11 Total Undiscounted Benefits for a 200-ft Average Effective Fracture Length Change

The undiscounted economic benefits of a fracture length change are convenient to present in this study because they are (1) easily determined from the marginal cost/resource supply curves* and (2) independent of when production will take place. Determining when benefits will occur in the future, as well as their discounted present value, amounts to knowing the time

*Note that marginal cost curves are based on ordering the recoverable resource by extraction cost grade. Each cost grade is composed of one or more permeability ranges (i.e., k-levels). There exists the possibility, although unlikely, that a change in fracture length to 1200 ft could allow a better grouping of k-levels into cost grades. If this regrouping lowered extraction costs, some additional benefits not shown in Fig. 11 would accrue as a result of the increased fracture length. In this sense, the benefits shown in Fig. 11 might be considered as <u>minimum</u> benefits.

path of production. But determining a production scenario is beyond the scope and purpose of this study.

The benefits calculations computed in this report, and presented in Fig. 11, are based on the extraction cost reduction of economic resources and the value of additional resources made economic by technology advancements. Therefore, at an assumed market price, of say $6.00/MCF, technology improvements create benefits in two ways:

1) for gas already economic at $6.00/MCF, its extraction cost decreases, and

2) additional gas, which was not economic at $6.00/MCF, now becomes economic. Benefits result from developing this gas to the extent that its extraction cost is now less than $6.00/MCF.

Hence, in this example, 'economic' is defined as earning a real rate of return of 15% with a selling price of $6.00/MCF.

Figure 12 presents the undiscounted benefits that accrue in each of the two above-mentioned categories for two selling prices, $4.00 and $6.00 per MCF. The undiscounted benefits that result from technology advancements at $6.00/MCF is greater than 150% of that which accrues at $4.00/MCF. The results presented in Fig. 12 are important because they illustrate that (1) undiscounted benefits from technology advancement (i.e., fracture length change) expand substantially at higher cost grades -- this is consistent with earlier findings that related the sensitivity of extraction cost to fracture length changes -- (2) more benefits arise due to extraction cost reductions when the market price for tight sands gas is $6.00/MCF, and (3) significant quantities of additional blanket resources do become economic as fracture length and selling price increase. Note that the benefits derived from increasing the availability of resource that is economic may be greater under the conditions where the market price of gas is low.

The undiscounted benefits described above measure only a portion of the total undiscounted benefits derivable from fracture-related R&D programs. The undiscounted benefits presented in this subsection focus on the pure technical progress of longer average achieved fracture lengths for a given fracturing cost budget. The average length increases either due to improved efficiency in sand transport or better predictability of fracture performance. Not included are benefits which could result from other kinds of technical advancement (i.e., improved tight gas sands detection) or could result from substantially larger fracture designs, say 4000 ft. Also, benefits accruing to tight sands gas basins other than the twelve appraised in the NPC study are not included in the previously presented results (i.e., extrapolated areas, proved reserves and resources in the twelve appraised basins that were not recovered due to the well-spacing constraint).

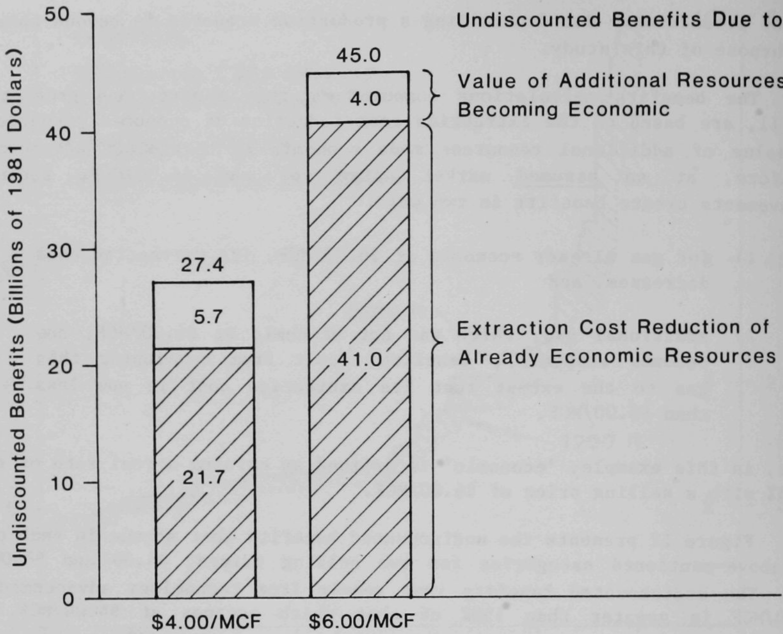

Fig. 12 Undiscounted Benefits by Category for a 1000- to 1200-ft Average Effective Fracture Length Change

6.3 EFFECTS OF LEARNING

As the results of R&D programs become available and as experience in tight gas sands basins increases, not only does the performance of the extraction technology improve, but risks also decline. Clearly, improved rates of reliability in drilling and fracturing, and increased knowledge of tight gas sands geology both reduce risks. This process of simultaneous technology advancement and risk reduction will be referred to as the effects of learning.

Some learning is generic in nature and thereby may be applicable in many circumstances and in many geographic locations. For example, better understanding of the theory of fracture propagation has wide applicability. Alternatively, other learning is either basin- or formation-specific and depends on the geologic characteristics of the tight gas reservoirs in a particular location. Fracture designs including fracture fluid volume, types of materials, and injection rate often evolve and improve as experience is gained in a particular area. For example, in developing the Wattenberg Field in the Denver Basin, Amoco has made huge strides in learning how to optimize fracture treatments.

Interpretation of risks is always difficult. Some risk reduction, like continued advancement in fracturing reliability, automatically both improves average performance and reduces risk simultaneously. In other cases it is not so simple. Geologic risks may be reduced by drilling up a basin. The outcome may yield the expected amount of recoverable gas, but it may also yield somewhat more or less than this expected quantity. A similar statement applies to technology advancement. The outcomes of R&D efforts are seldom predicted precisely.

Figures 13-15 show sensitivity results by region for changes in both fracture length and required rate of return (reflecting risk). The shape and relative position of each of the three marginal cost curves are distinct for each region. However, as Table 7 summarizes, the total average percent reduction in extraction costs due to simultaneous technology advancement and risk reduction is fairly stable and has only a small degree of variance across regions. Although the total effects of learning within each region are approximately the same, some regions may be slightly more sensitive to risk reduction and others to technology advancement. In summary, it is seen through Figs. 13-15 and Table 7 that very large extraction cost reductions are achievable through learning.

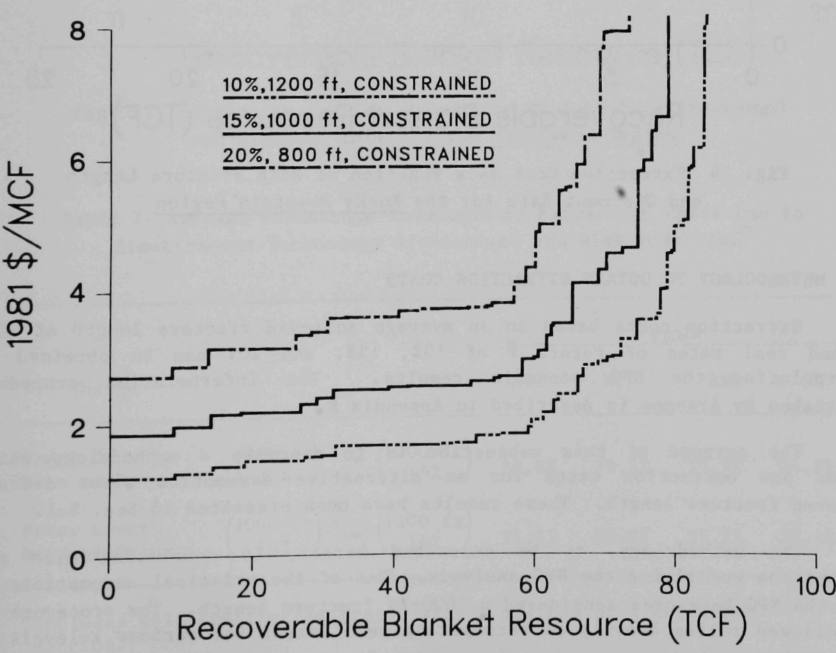

Fig. 13 Extraction Cost as a Function of Both Fracture Length and Discount Rate for the Northern Great Plains Region

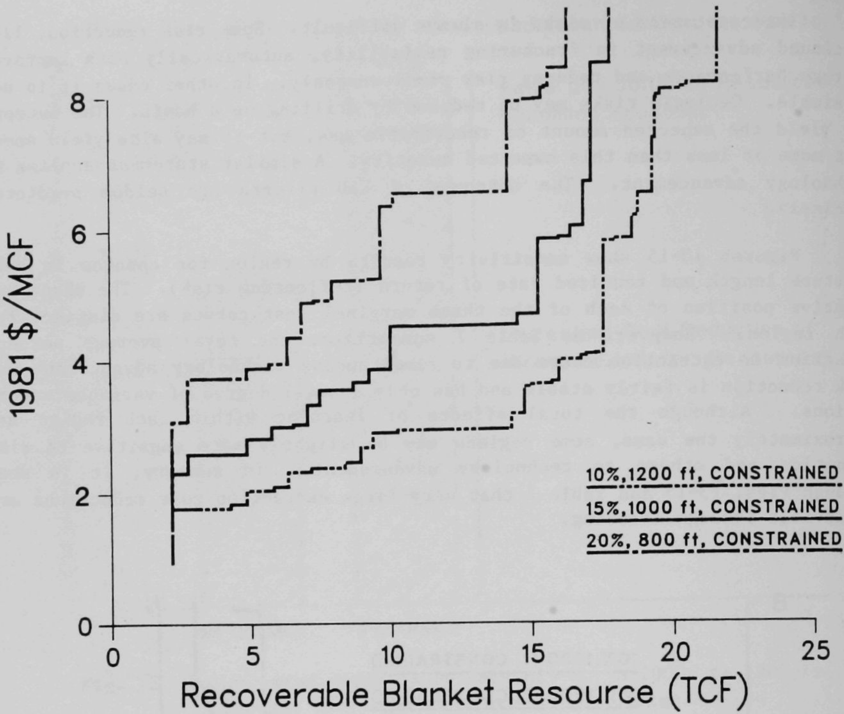

Fig. 14 Extraction Cost as a Function of Both Fracture Length and Discount Rate for the Rocky Mountain Region

6.4 METHODOLOGY TO OBTAIN EXTRACTION COSTS

Extraction costs based on an average achieved fracture length of 1000 ft and real rates of return $\bar{r}$ of 10%, 15%, and 20% can be obtained by interpolating the NPC economic results. The interpolation procedure undertaken by Argonne is described in Appendix B.

The purpose of this subsection is to describe a methodology which yields new extraction costs for an alternative assumption about average achieved fracture length. These results have been presented in Sec. 6.1.

The methodology, to be described herein, is consistent with the assumptions underlying the NPC analysis. One of the principal assumptions is that the NPC base case considered a 1000-ft fracture length. The procedure to be followed relies heavily on recomputing well output for various k-levels in each subbasin study area under alternative fracture length assumptions. Well production is estimated using type curves as described in Appendix C.

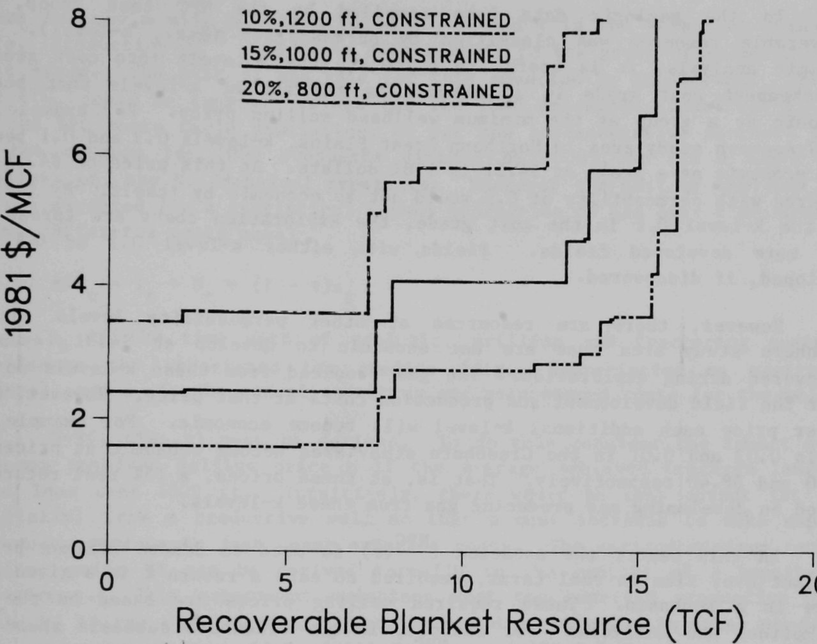

Fig. 15 Extraction Cost as a Function of Both Fracture Length and Discount Rate for the Southwest Region

Table 7 Average Percentage Reduction in Extraction Costs Due to Simultaneous Technology Advancement and Risk Reduction[a]

			Region		
Change					
		All	NGP	RM	SW
Frac. Length Rate of Return	(800 ft, 20%) → (1000 ft, 15%)	33.8%	33.2%	33.5%	34.2%
Frac. Length Rate of Return	(1000 ft, 15%) → (1200 ft, 10%)	35.1%	35.2%	33.2%	35.4%

[a]Includes well-spacing constraint with a maximum of 4 wells per section.

In the geologic data base compiled by the NPC task group, the recoverable resource was classified by permeability (i.e., k-level). For economic analysis, it is useful to aggregate the k-levels into cost grades. The cheapest cost grade in a subbasin is the set of k-levels that become economic as a group at the minimum wellhead selling price. For example, in the Greenhorn study area in Northern Great Plains, k-levels 0.3 and 0.1 become just economic as a group at \$4.31 in 1981 dollars. At this price of \$4.31 the resource with permeability of 0.3 would not be economic by itself. By including the k-level 0.1 in the cost grade, the exploration costs are spread out over more developed fields. Fields with either k-level 0.3 or 0.1 are developed, if discovered.

However, there are resources at other permeability levels in the Greenhorn study area that are not economic to develop at \$4.31, even if discovered during exploration. The gas produced from these k-levels do not cover the field development and production costs at that price. However, at a higher price each additional k-level will become economic. For example, k-levels 0.03 and 0.01 in the Greenhorn study area become economic at prices of \$5.80 and \$8.40 respectively. That is, at these prices, a 15% real return is earned on developing and producing gas from these k-levels.

In this report the notation $c^{NPC}(\bar{r})$ is used to denote minimum price, constant over time in real terms, required to earn a return $\bar{r}$ in a given cost grade in a subbasin. These required selling prices are based on the NPC assumptions and analysis. For example, in the Greenhorn subbasin there are three cost grades with values of $c^{NPC}(\bar{r})$ of \$4.31, \$5.80 and \$8.40 for $\bar{r}$ = 15%. Table D.1 in Appendix D shows a list of subbasin study areas and the cost grades within each subbasin.

The purpose here is to derive the required selling price (i.e., extraction cost) for an alternative fracture length assumption x_f. The revised extraction cost is denoted by $c(x_f,\bar{r})$. In performing these sensitivity analyses the same grouping of k-levels was used as in the NPC analysis. The grouping of k-levels pertains to the cheapest cost grade in a subbasin (e.g., k = 0.3 and 0.1 in the cheapest cost grade in Greenhorn). Conceivably with a fracture length x_f different from 1000 ft, extraction cost could be somewhat reduced by an alternative grouping of k-levels into cost grades. However, the cases where this might arise are likely to be few, if any, and the effects on estimated extraction costs are likely to be small even if such a case were to arise.

Below, the methodology used to obtain the revised $c(x_f,\bar{r})$ values will be derived and described. First, it is necessary to precisely define the NPC extraction costs. The $c^{NPC}(\bar{r})$ is the selling price p, constant in real terms, such that the expected value of after-tax revenues equals the expected value of after-tax cost (ATC) discounted at a rate $\bar{r}$.

$$\alpha \sum_{t=1}^{30} pQ_t^{NPC} (1 + \bar{r})^{-t} = \sum_{t=1}^{30} ATC_t(1 + \bar{r})^{-t}$$

where for now α will be taken to be $1 - \tau$ and τ is the effective income tax rate. Production Q_t^{NPC} and costs ATC_t pertain to the group of k-levels in the cost grade. The unit of analysis for this equation is immaterial. The Q_t^{NPC} and ATC_t could be expected values for the 1000 prospects (identical ex ante) in the NPC Monte Carlo simulation, or for one representative prospect (equal to the outcome for 1000 prospects divided by 1000), or for a basin which consists of, say N, identical prospects. Whatever the unit of analysis, Q_t^{NPC} is the expected (in a statistical sense) production of gas over time from that unit. After-tax costs equal

$$ATC_t = I_t - D_t + (1 - \tau)a_t$$

where I_t is the time path of geologic, drilling and fracturing costs, D_t represents the associated tax credits (e.g., depreciation on capitalized assets), and a_t is the annual operating and maintenance costs for the wells.

Next, $c(x_f,\bar{r})$ must be derived. To do this consider the impact on the minumum required selling price p if the average achieved fracture length x_f were less than 1000 ft. Intuitively, there would be less output (at least initially) from a productive well so that p must increase to make expected revenues continue to just cover expected costs. The revised minimum required selling price p* can be derived formally in the context of a hypothetical experiment. This experiment questions what the expected production $Q_t(x_f)$ would be if the same costs ATC_t were incurred as before. In other words, the same number of wells could be drilled as were drilled before.

The revised p* must satisfy

$$\alpha \sum_{t=1}^{30} p^*Q_t(x_f)(1 + \bar{r})^{-t} = \sum_{t=1}^{30} ATC_t(1 + \bar{r})^{-t}$$

Since after-tax expected costs on the right-hand side remain unchanged, the after-tax expected revenues on the left-hand side can be equated as follows:

$$\alpha \sum_{t=1}^{30} c(x_f,\bar{r})Q_t(x_f)(1 + \bar{r})^{-t} = \alpha \sum_{t=1}^{30} c^{NPC}(\bar{r})Q_t^{NPC}(1 + \bar{r})^{-t}$$

Note that α on each side cancels. Some details on the determination of α and Q_t are discussed below. It will be shown that for the purpose of computing the revised extraction cost, Q_t^{NPC} and $Q_t(x_f)$ can be taken as the output per well if only one k-level is in the cost grade or the weighted average of well outputs if multiple k-levels are in the cost grade.

Solving for $c(x_f,\bar{r})$ yields

$$c(x_f,\bar{r}) = c^{NPC}(\bar{r}) \left[\left(\sum_{t=1}^{30} Q_t^{NPC}(1 + \bar{r})^{-t} \right) \div \left(\sum_{t=1}^{30} Q_t(x_f)(q + \bar{r})^{-t} \right) \right]$$

This is the formula that was used to obtain extraction costs for alternative fracture lengths x_f. For example, Table D.1 in Appendix D shows the values of $c(x_f,\bar{r})$ by cost grade in each subbasin study area. For example for the cheapest cost grade in the Greenhorn subbasin $c(x_f,\bar{r})$ = \$4.70 for x_f = 800 ft, whereas $c^{NPC}(\bar{r})$ = \$4.31 for $\bar{r}$ = 15%. The above formula also emphasizes that what matters for extraction costs is not the effect of fracture length on ultimate recovery but rather the effect on discounted production. Obtaining revenues sooner increases their present value.

Some details of the procedure should be noted. First, the firm is interested only in its revenue net of the one-eighth royalty. This revenue is given by

$$\frac{7}{8}(1 - \tau) \sum_{t=1}^{30} p_t Q \quad (1 + \bar{r})^{-t}$$

Redefine α in the text as $\alpha = (7/8)(1 - \tau)$. The α still cancels and the extraction cost formula remains unchanged.

Suppose that the cost grade consists of one k-level. Given a drilling budget, suppose that n wells can be drilled. The production is

$$\tilde{Q}_t = nq_t(k)$$

where q_t is output per well with permeability k. However, the size of the drilling budget is irrelevant for the extraction cost formula, since the NPC analysis does not include any scale economies or diseconomies in developing basins. This is seen by noting that revenue is given by

$$\frac{7}{8}(1-\tau)n \sum_{t=1}^{30} pq_t(k)(1 + \bar{r})^{-t}$$

Hence, α and Q_t can be redefined as $\alpha = (7/8)(1 - \tau)n$, which cancels, and

$$Q_t = q_t(k).$$

That is, for the extraction cost formula, production can be viewed as simply the output per well.

Next suppose that the cost grade consists of m k-levels. Now the Q_t can be taken to be the weighted average of the well production $q_t(k_i)$ in k-level i.

$$Q_t = f_1 q_t(k_1) + \dots + f_m q_t(k_m)$$

where the fractions f_i sum to one. Again, the size of the drilling budget is irrelevant for the extraction cost formula, since the size effect can be included in α, which cancels. To implement the extraction cost formula the f_i's were computed as follows:

$$f_i = n_i \div \sum_{j=1}^{m} n_j$$

where n_i is the number of productive wells (recognizing a possible well-spacing constraint) calculated in the NPC study to fully extract k-level i.

Well production by k-level in a subbasin as a function of fracture length is computed using "type curves" calibrated to a reservoir simulation model (see Appendix C).

Finally, suppose that development drilling is distributed over T years with Θ_j being the share of drilling in year j. It can be shown that revenue becomes

$$\frac{7}{8}(1 - \tau)n\left[\Theta_1 + \frac{\Theta_2}{(1 + \bar{r})} + \dots + \frac{\Theta_T}{(1 + \bar{r})^{T-1}}\right]\sum_{t=1}^{30} pQ_t(1 + \bar{r})^{-t}$$

where, as before, Q_t is defined as the weighted average production per well in the cost grade. Again α is redefined, but since α cancels out, the extraction cost formula is not affected.

In deriving the above formula the question was asked: Given a fixed budget, what is the required selling price if well production is based on a fracture length of x_f rather than 1000 ft? This provides a suitable framework to impute extraction costs since the size of the budget is irrelevant to compute gas costs on a \$/MCF basis. This approach to deriving extraction costs implies nothing about the actual budgets, i.e., expenditures and number of wells that are needed to fully extract the recoverable resource in a basin.

To actually compute the required number of wells the procedure used by NPC was followed. The NPC computed the required number of productive wells n to extract the maximum recoverable gas (MRG) as

$$n = \frac{MRG}{CUM(x_f)}$$

where $CUM(x_f)$ is the cumulative production per productive well over 30 years with achieved fracture length x_f. If $x_f < 1000$ ft and if thereby ultimate recovery, i.e., $CUM(x_f)$, is reduced, then more wells are required to produce the recoverable resource.

7 REGULATIONS AND INSTITUTIONAL RESTRICTIONS PERTINENT TO THE DEVELOPMENT OF TIGHT SANDS GAS

Well-spacing and wellhead price regulations affect the production economics, recoverable resource and marketability of tight sands gas. Similarly, institutional restrictions that preclude the development of the recoverable blanket sands resource due to federal lands designations reduce the quantity of available resource. In this section, these three areas are addressed in varying degrees of detail. The effects of well-spacing regulations on the recoverable resource are both qualitatively and quantitatively analyzed (Sec. 7.1). Section 7.2 presents the undiscounted economic benefits that accrue from the removal of well-spacing regulations applicable to tight sands gas. Descriptive discussions of wellhead price regulations and the institutional restrictions to the recoverable blanket resource appear in Secs. 7.3 and 7.4, respectively.

7.1 WELL-SPACING REGULATIONS: DESCRIPTION AND EFFECTS

The NPC Base Case analysis of the recoverable tight sands gas resource is based on a maximum drilling density of four wells per section. That is, there must be at least 160 acres per well. This constraint was applied to the resource supply curves presented in Sec. 2.4. In this subsection, the effects of relaxing this regulation are presented. Both the maximum recoverable resource, as well as the recoverable resource under less stringent regulations, are shown as a function of extraction cost. Before these findings are introduced, the nature and purpose of well-spacing regulations are discussed.

7.1.1 Background

Well-spacing regulations are one group from a wide spectrum of state laws that restrict the means by which oil and natural gas may be produced. State oil and gas conservation laws generally are intended to prevent damage to surrounding aquifers and land, minimize the waste of the hydrocarbon resource, reduce instability of production and prices, and eliminate inequities among producers. Other types of conservation regulations include specifications on how to case and plug wells, restrictions on salt water disposal, gas-oil ratio limitations on production, gas venting and flaring restrictions, and direct production limitations.[27]

Well-spacing regulations are intended to limit the number of wells that may be used to produce gas from a particular reservoir. Several purposes are served by these regulations, including reducing the rate of production. Reducing the rate of production from the reservoir may under some circumstances increase the ultimate recovery from the reservoir. During earlier periods when there was surplus supply of gas, well-spacing regulations assisted in controlling supply. The regulations also reduce waste and safety hazards introduced by multiple land owners who attempt to overdevelop their portion of the reservoir in order to obtain a larger share of the total production. This externality arises from poorly defined property rights for the underground gas resource. Well-spacing restrictions may also help the competitive position of small producers who may have financial constraints on their capital availability and, hence, on the number of development wells they can afford to drill.

Typically, well-spacing regulations limit well location in three ways 1) they stipulate the maximum number of wells per section on land overlying the reservoir;* 2) they specify the distance between and around wells so that wells may not be spaced less than a given number of feet from other wells and 3) they identify the distance (feet) that wells may be sited relative to any property boundary.

It is not clear to what extent states with tight sands gas resources will permit development of an alternate well-spacing system tailored to the needs of tight sands gas producers. Texas law permits the Texas Railroad Commission, which administers Texas well-spacing regulations, to alter the regulations in individual circumstances. Alternatively, Ohio, where considerable Devonian shale drilling has been taking place recently, only permits up to a 5% variance from its prescribed well-spacing limits.

Even in states like Texas, however, the method of relaxing well-spacing regulations keeps tight sands gas producers from being on an equal footing with conventional natural gas producers. Each well-spacing rule waiver requires a "special field rule" to be granted by the full Texas Railroad Commission. A conventional producer in Texas can operate under the usual well-spacing regulations and need only file information with the Commission to obtain a waiver. In contrast, the tight sands gas producer can obtain the needed waiver only after a special hearing at which the producer bears the burden of proving the special geology necessitating a denser well spacing. A further potential problem is that neighboring producers may come to protest at the hearings. Furthermore, a decision on such a waiver request can take three months longer than the approval of a conventional well-spacing plan. Thus, the tight sands gas producer faces additional litigation fees, carrying costs, production delays, and the risk of an adverse decision that conventional producers in Texas need not generally consider.

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*"The regulations vary widely from state to state, but in the typical case they provide for minimums (subject to exceptions) of 40-acre spacing for oil wells and 160-acre spacing for gas wells." (Ref. 27 p. 45.)

7.1.2 Alternative Regulations for Tight Formations

In the NPC study, the well-spacing constraint was modeled to allow a maximum of 4 wells per section. As illustrated above, some states permit exceptions to their well-spacing regulations that allow more wells per section in tight sands formations. States that do not permit allowances to their well-spacing regulations indirectly promote the development of conventional gas reservoirs and, thereby, cause a loss of recoverable resource from tight sands formations. When this situation is generally recognized, states may implement special regulations or waiver procedures that apply to tight sands formations. As an example of these alternatives, suppose the well-spacing regulation stated that six wells per section could be allowed if permeability k is less than or equal to 0.01 md. The sensitivity of a well-spacing regulation permitting 6 wells per section is shown in Fig. 16. This figure illustrates that the loss of recoverable resource in the poorer resource grades is substantially reduced as the number of wells allowed to extract the resource is increased. The effects of well-spacing regulations on the

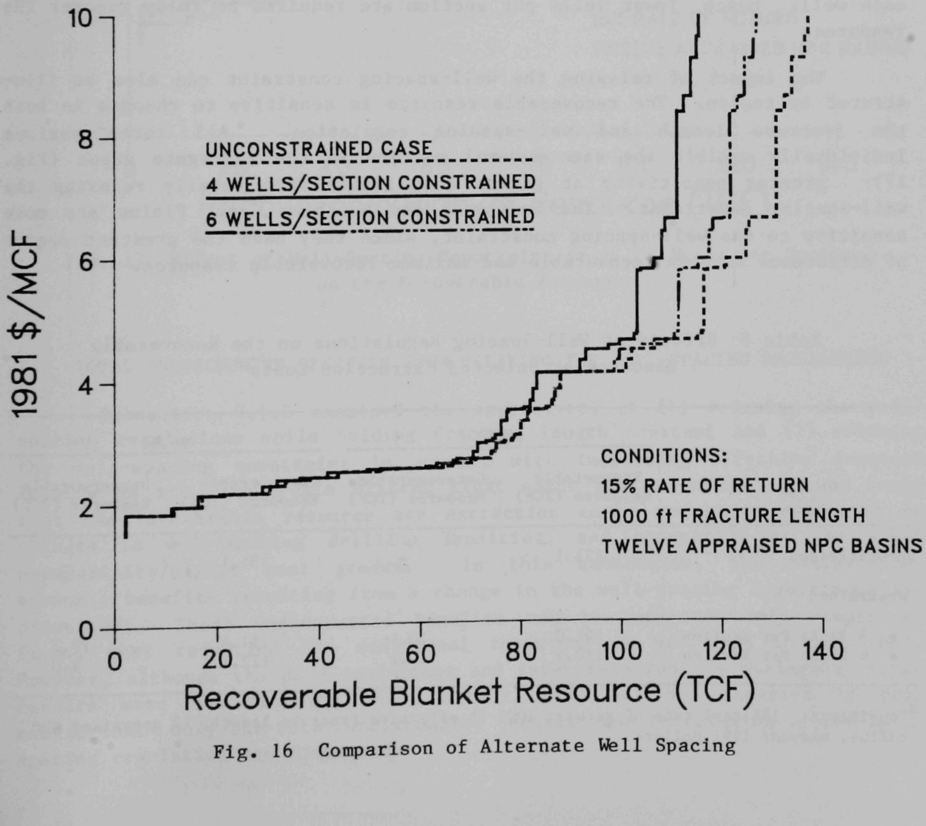

Fig. 16 Comparison of Alternate Well Spacing

recoverable resource are summarized in Table 8 for the 1000-ft effective fracture length.

7.1.3 Effects on the Recoverable Resource

The importance of a well-spacing constraint is greater for very low permeability, higher cost, tight sands gas grades. The better cost grades in the tight sands gas resource can usually be efficiently produced at less than or equal to 4 wells per section. Figures 16 and 17 show the impact on higher cost grades of relaxing the well-spacing constraint for the total appraised blanket sands resource base. The maximum recoverable resource (i.e, unconstrained case) substantially exceeds the recoverable resource with the well-spacing constraint (i.e., constrained case) at higher extraction cost grades. Also, as effective fracture length increases from 800 ft to 1000 ft, the gap between the constrained and maximum recoverable resource curves tends to become smaller. This result can be seen in Fig. 17. The reason for this tendency is that, in very poor permeability tight sands formations, an increased fracture length increases the ultimate (i.e., 30-year) recovery from each well. Hence, fewer wells per section are required to fully recover the resource.

The impact of relaxing the well-spacing constraint can also be illustrated by region. The recoverable resource is sensitive to changes in both the fracture length and well-spacing regulation. All three regions individually exhibit the same general pattern as the aggregate graph (Fig. 17): greater sensitivity at higher cost grades from totally relaxing the well-spacing constraint. The Southwest and Northern Great Plains are more sensitive to the well-spacing constraint, since they have the greatest degree of difference between recoverable and maximum recoverable resource.

Table 8 Effects of Well-Spacing Regulations on the Recoverable Resource at Selected Extraction Costs[a]

	$4.60		$6.64	
Case	Recoverable Resource (TCF)	Unrecoverable Resource (TCF)	Recoverable Resource (TCF)	Unrecoverable Resource (TCF)
Unconstrained	121.1	-	131.1	-
Constrained				
• 4 Wells Per Section	101.0	20.1	111.4	19.7
• 6 Wells Per Section	110.9	10.2	122.1	9.0

[a]Conditions: 15% real rate of return, 1000-ft effective fracture length, 12 appraised NPC basins, midyear 1981 dollars.

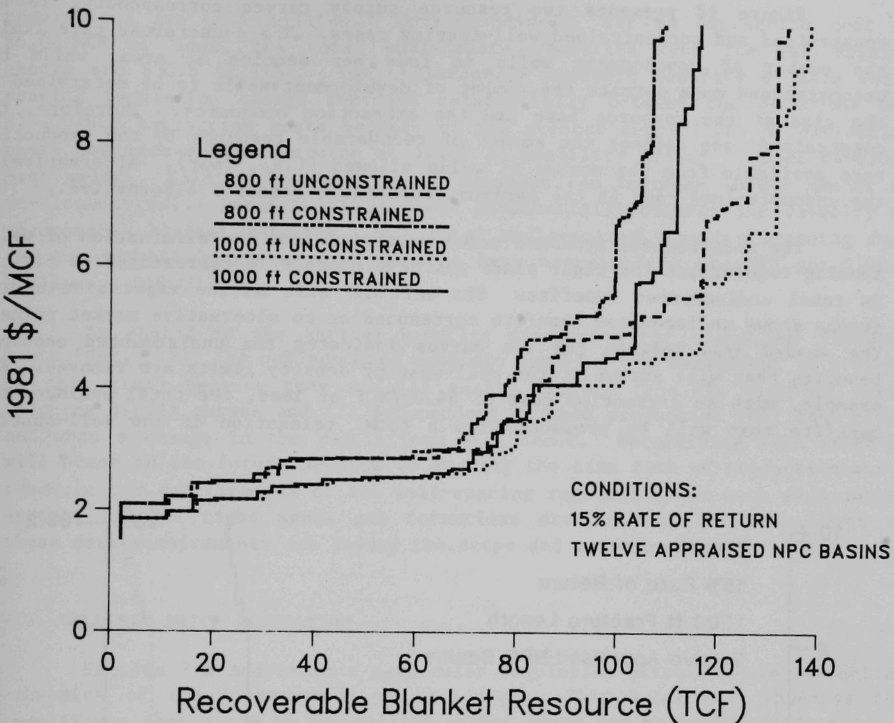

Fig. 17 Effect of Well-Spacing Constraint (i.e., 4 Wells per Section) on the Recoverable Resource

7.2 TOTAL UNDISCOUNTED BENEFITS FROM RELAXING THE WELL-SPACING REGULATIONS

Subsection 7.1.3 examined the sensitivity of (1) relaxing the well-spacing regulations while holding fracture length constant and (2) relaxing the well-spacing constraint in concert with increasing effective fracture lengths on the recoverable blanket tight sands gas resource. It was found that the recoverable resource and extraction costs are quite sensitive to changes in well-spacing drilling densities, and especially at the lower permeability/higher cost grades. In this subsection, the undiscounted economic benefits resulting from a change in the well-spacing regulations are presented. These undiscounted benefits can be separated into components (i.e., cost reduction and additional resource) as was done in Sec. 6.2. However, although the data conditions and interpretation are analogous, these results were not prepared and, thereby, will not be presented in this subsection. Only the total undiscounted benefits due to relaxing of the well-spacing regulation are addressed.

Figure 18 presents two resource supply curves corresponding to the constrained and unconstrained well-spacing cases. The constrained case limits the number of development wells to four per section or area, while the unconstrained case permits the number of development wells to be determined by the size of the resource base and the extraction economics. Therefore, the constrained case defines the amount of recoverable resource by the production rate available from the number of wells allowed (i.e., four). Alternatively, the unconstrained case is the maximum recoverable resource alternative.

The undiscounted economic value resulting from the elimination of well-spacing regulations for tight sands gas developments is represented in Fig. 18 as total undiscounted benefits. The vertical axis on the right side of the graphs shows undiscounted benefits corresponding to alternative market prices. The shaded area between the two curves indicates the undiscounted economic benefits that will accrue if the well-spacing density limits are removed. For example, with an extraction cost of \$4.00/MCF or less, the total undiscounted benefits that will be produced from a total relaxation of the well-spacing

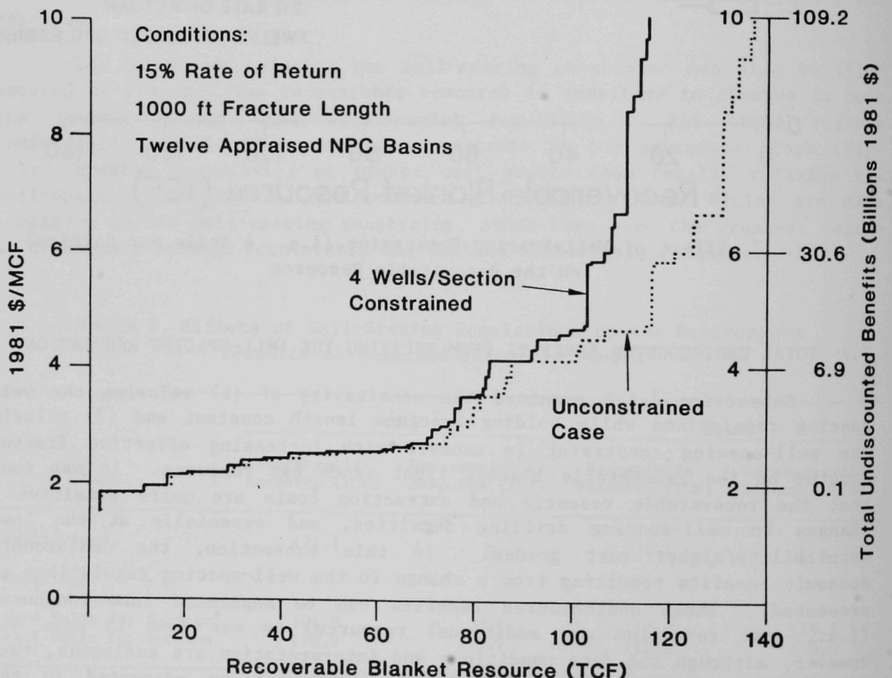

Fig. 18 Total Undiscounted Benefits from a Change in the Well-Spacing Regulations

regulations are $6.9 billion. Correspondingly, for an extraction cost of $6.00/MCF or less, the total undiscounted benefits from the well-spacing change are $30.6 billion. The undiscounted economic benefits of this well-spacing regulation change increase substantially between the $4.00/MCF and $10.00/MCF extraction costs because of the greater sensitivity of extraction costs and recoverable resource at lower permeability grades to more development wells. Holding fracture length constant, an increase in the number of development wells permitted in a field substantially expands the quantity of recoverable blanket resource. The total undiscounted benefits accruing from the recoverable blanket sands resource base appraised by the NPC are $109.2 billion at $10.00/MCF.

As stated in the earlier benefits discussion for technology improvements (Sec. 6.2), the undiscounted economic benefits are convenient to present in this study because they are (1) easily derived from the marginal cost/resource supply curves and (2) independent of when production will take place and when a change in the regulations will occur. Determining when benefits will occur in the future amounts to knowing the time path of production and a schedule for modification of the well-spacing regulations in each state where western blanket tight sands gas formations are located. However, both of these data requirements are beyond the scope and purpose of this study.

7.3 WELLHEAD PRICE REGULATION

Section 7.2 addressed a particular regulation affecting the production economics of the tight sands gas resource. This subsection examines the regulations that apply to the selling/market price for the tight sands gas.

Development of western tight sands gas will be affected significantly by both federal and state laws. Long a strictly-regulated commodity, natural gas production of all categories is restricted by laws (to varying degrees) which determine selling price, the location of wells, the siting of pipelines, taxation levels, and numerous other factors which affect profitability. The purpose of this section is to focus on the wellhead pricing of tight sands gas under the Natural Gas Policy Act (NGPA) of 1978.

Until passage of the NGPA,[28] natural gas was the subject of perhaps the most complicated economic regulations in the history of the federal government. Pre-NGPA regulation had been under the authority of the Natural Gas Act of 1938,[29] which displaced exclusive state regulation of natural gas development and established a system of price controls that initially applied only to pipeline transmission. However, in 1954, the United States Supreme Court held in *Phillips Petroleum Co. v. Wisconsin* that the Natural Gas Act required the Federal Power Commission (now the Federal Energy Regulatory Commission, FERC) to regulate the price charged by natural gas producers at the wellhead for gas which was to be transported between states.[30]

Passage of the NGPA was intended to rectify the difficulties which arose as a result of the court case.[31] First, the Act largely eliminated the pricing distinctions between the intrastate and interstate markets. Second, the NGPA abolished the utility pricing method in favor of gradual price decontrol for the majority of natural gas. Third, the Act mandated that certain low-priority gas consumers subsidize the price paid by high-priority users through a system called "incremental pricing."

The NGPA does not mean immediate price decontrol for most natural gas. Rather, the Act divides all natural gas into some 27 different categories depending on the circumstances of discovery (e.g., onshore, offshore, new, old, etc.), grants to each a different formula for calculating its "maximum lawful price" and mandates a schedule by which many of these categories of gas are to be decontrolled. Free market pricing is to be achieved for most new contracts by 1987. The rationale behind this long transitional period is that the change in natural gas pricing is so dramatic that consumers must be given an adjustment period before the full impact of free market pricing is felt.[32]

The NGPA can be expected to strongly influence tight sands gas production. First, tight sands gas which qualifies as tight formation gas under the NGPA is entitled to be sold at a quite high, if regulated, price. Second, before being sold at retail, tight sands gas at current prices will be averaged with lower-priced categories of gas, rather than being "incrementally priced." The method of incremental pricing for tight formation gas was investigated by Argonne together with some of the incentives that result from this pricing scheme.[7]

7.3.1 Definition of Tight Formation Gas

The regulations implementing the NGPA contain a very precise definition of tight sands gas, labeled "tight formation gas" in the regulations.[33] The definition has several components:

1. The gas must be located in a geological formation which FERC designates, upon the recommendation of a state public utility commission (or, in the case of federal lands, the appropriate federal agency), to meet the following criteria:

   - Formation permeability must be 0.1 millidarcy or less.[34]

   - The stabilized production rate, without stimulation, of natural gas from the formation is not expected to exceed specified amounts depending on depth.

- No well drilled into the formation is expected to produce, without stimulation, more than five barrels per day of crude oil.[35]

2. Each tight sands gas well must be drilled starting on or after July 16, 1979, and be determined by the state public utility commission (or appropriate federal agency)[36] to be within a formation designated by FERC as a tight formation.[37] Failure by FERC to overrule this decision within 45 days of being notified constitutes agreement.[38]

7.3.2 Maximum Lawful Price for Tight Sands Gas

Once a natural gas well has been designated as a tight sands gas well, its owner is entitled to sell the gas at a relatively high price if the market will bear it. The maximum lawful price for tight sands gas is pegged at 200% of the maximum lawful price for new onshore production wells,[39] another category of natural gas created by NGPA. The price for new onshore production wells is set monthly by FERC and is calculated by multiplying the April 1977 designated base price of \$1.75 per 10^6 Btu by an "inflation adjustment factor,"[40] based on the Gross National Product (GNP) implicit price deflator from the previous quarter, plus a correction factor of 0.2% per month. For example, P_n, the price for tight sands gas in December 1982, is computed by multiplying P_{n-1}, the price of such gas in November 1982 (\$5.396/MCF), by the following inflation adjustment factor:

$$P_n = P_{n-1}\left[\frac{GNP}{100} + 1.002\right]^{1/12}$$

$$= \$5.396\left[\frac{3.7}{100} + 1.002\right]^{1/12}$$

$$= \$5.420$$

where GNP is the percent change in the implicit GNP price deflator during the relevant quarter of 1982, expressed as an annual rate. The maximum lawful price does not generally include state severance taxes and it is only an upper limit, not a guaranteed return. The maximum lawful price for tight sands gas for January 1983 is \$5.444/MCF.

7.4 RESTRICTIONS DUE TO FEDERAL LANDS

Regulations affecting tight sands gas production economics and pricing are addressed in the previous subsections. Institutional restrictions on the development of tight sands gas are reviewed in this subsection. One important question regarding the size of the recoverable tight sands gas resource is the extent to which development will be permitted in federally owned lands and areas adjacent to federally owned lands.

7.4.1 Development on Federal Lands

Development of any kind, including tight sands gas, is restricted or prohibited altogether in a number of categories of federal lands. The NPC study estimates that up to 5% of the total tight sands gas resource might be excluded from development because the resource is located in such lands as national parks, wildlife refuges, or wilderness study areas. The region with the greatest potential development withdrawal is Northern Great Plains, where some 9% of the tight sand gas resource might be made unavailable for development.

An additional dimension to this problem is suggested in a recent Data Resources Inc. (DRI) report.[41] This report suggests that a broad estimate of how much oil and natural gas on federal lands is being withheld from development must go beyond quantifying the effects of such formal decisions as national park or wilderness study area designations. It contends that less formal decisions such as administrative withdrawals and de facto withdrawals of oil and natural gas prospects pending final disposition of these lands have prevented some development for many years, even though no formal decision has ever been made. In addition, the DRI study points out several other categories of federal lands as possibly being unavailable for development, including Department of Defense lands and Indian reservations. Finally, the DRI report suggests that the complicated federal regulations, which govern development where oil and natural gas activities are allowed, are themselves a major deterrent to such development: two studies are cited which conclude that some 30-40% of the federal land outside of Alaska was effectively closed off to energy development <u>before</u> the major withdrawals created by the Bureau of Land Management and Forest Service wilderness studies began. Thus, the amount of tight sands gas which is estimated in the NPC study to be directly withdrawn from development may, in fact, be larger due to the economic and regulatory impact of restrictive federal land-use policies.

7.4.2 Development on Lands Adjacent to Federal Lands

An additional potential obstacle to western tight sands gas development is posed by the problem of access across federal land to wells located on private lands or federal leases. The development of tight sands gas depends as much on the ability to bring the recovered natural gas to market as on the ability to locate and produce it. The need to build roads and pipelines to wells may itself become a major obstacle to development if the only practical route is across federal property, especially if the federal land is classified to prohibit or restrict development. At least one recent federal court decision, *State of Utah v. Andrus* [486 F. Supp. 95 (D. Utah 1979)], held that a uranium mining company was not entitled to an access road across a wilderness study area to its lease on adjoining federal lands. It can be anticipated that some amount of the western tight sands gas resource additional to that noted in the NPC study will be uneconomic to develop because of the difficulties and expense of obtaining access permission across adjoining federal lands, and that some development may be effectively prohibited altogether.

8 NEAR-TERM DEVELOPMENT POTENTIAL OF APPRAISED WESTERN BASINS: SUMMARY RESULTS

The previous sections examined the technological, economic and institutional/regulatory factors that might affect gas supply availability from tight blanket sands formations. These factors (i.e., rate of return, risk premium, well-spacing regulations and fracture length) were found to have substantial effects on the recoverable blanket tight sands gas resource and its extraction cost grades. Some of the impediments to the near-term development of blanket tight sands gas are summarized in this section.

Near-term development of western tight sands gas depends primarily on three factors: extraction cost, pipeline accessibility and technology adaptability. The purpose of this section is twofold. The first purpose is to highlight the key issues and problems that may affect the near-term development potential of tight sands gas, and the second is to rank the formations according to their regional capability for development. Section 8.1 summarizes the accessibility of pipelines by each of the three western tight sands gas regions. This is followed by a discussion of some special geologic problems associated with the basins, and the availability and adaptability of the technology to handle these problems (Sec. 8.2). Then, each of the basins are ranked within their respective region according to their extraction cost grades, pipeline accessibility and state of fracturing technology (Sec. 8.3). Finally, in Sec. 8.4, the undiscounted incremental benefits of developing each basin and region under select technological and regulatory conditions are illustrated relative to a base case.

8.1 PIPELINE ACCESSIBILITY BY THE TIGHT SANDS GAS BASINS*

The historical development of the U.S. natural gas pipeline system represents a pattern of linking gas-producing basins with demand regions. During the last 20 years very few major modifications have been made to the basic interstate network of transporting natural gas from the south central gas fields of Texas,. Louisiana, and the Gulf of Mexico to the primary demand centers of the Midwest, and East and West Coasts. Gathering lines to new production areas within existing fields and some looping projects have been the principal additions made to the network, until recently. The delivery pattern indicated above, and illustrated in Fig. 19, is likely to change somewhat in order to accommodate supply interconnections with new resource areas. The supply source interconnection of concern in this report is with

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*This section summarizes a more detailed evaluation of pipeline accessibility and capacity availability prepared by Argonne that supports the findings and statements highlighted in this section.[7]

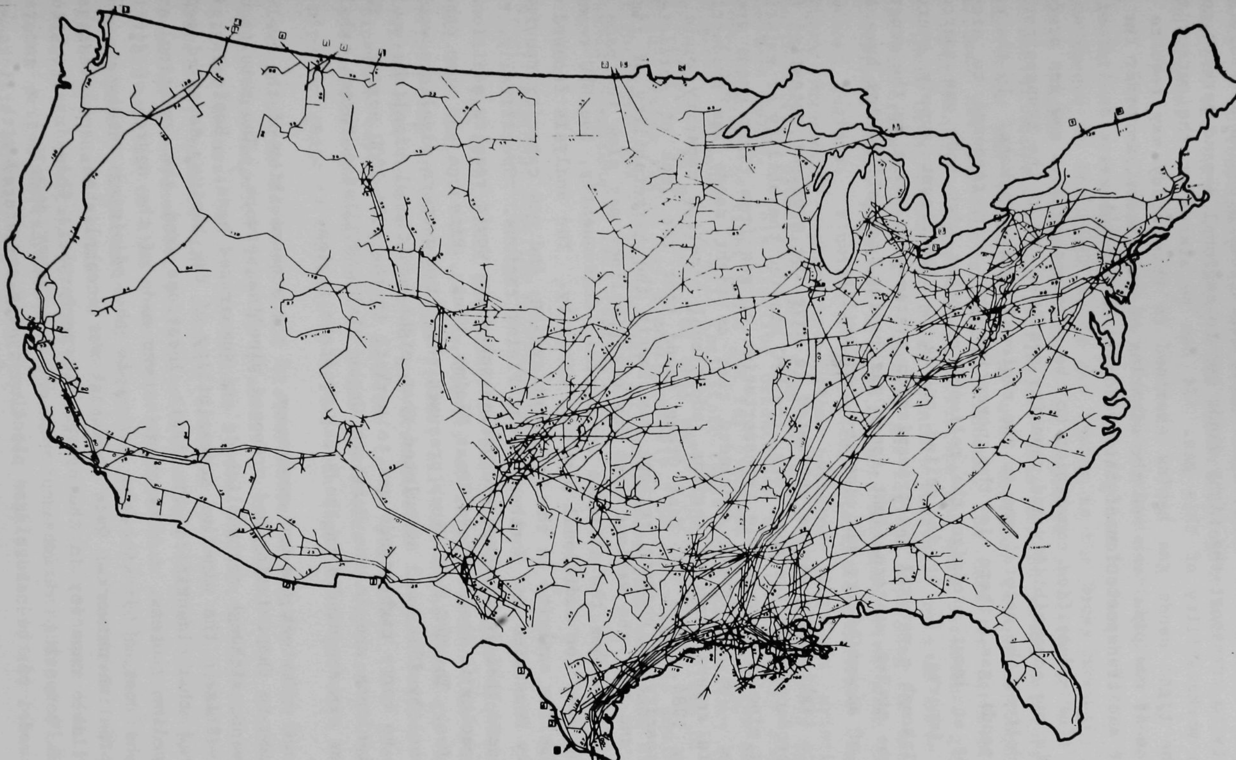

Fig. 19 Major Natural Gas Pipelines of the United States

western tight sands gas basins. The lack of sufficient pipeline accessibility and capacity to transport the tight sands gas to regional demand markets could impair the marketability of this gas. It can be stated at the outset that some of the tight sands gas basins examined in this study may require the construction of new pipelines and the clearing of new routes, in order for the development and transportation of this resource to take place.

One often-identified constraint to the development of a new gas production area is the accessibility and capacity availability of the transportation system to deliver the natural gas to the regional demand markets. In the case of tight sands gas, there is the potential for this resource to either displace or at least minimize the reliance on other high cost gas sources, especially imports, if it is relied on as a significant supply source. However, although a natural gas transmission system does exist in the general areas of the twelve western tight sands gas basins, not all basins have the same level of accessibility and capacity availability.

Since tight sands gas is estimated to have the greatest potential for increased production in the near term, the NPC studied the ability of existing and planned pipelines to handle transportation of gas from tight sands areas to markets. The NPC report concluded that as tight sands gas production increases in several western regions, additional pipeline capacity would be required by 1984. The NPC Task Group found that the lack of sufficient pipeline capacity in certain regions may impair the marketability of tight sands gas, and that the serious need for new pipelines may slow the pace at which this gas reaches the ultimate consumers. Consequently, the NPC report assessed the need for additional pipeline capacity. The analysis focused on existing pipeline capacity in the Southwest region, and new capacity required in the Rocky Mountains and Northern Great Plains regions. Specifically, the NPC study found that its assumed production schedules would require additional pipeline capacity in the Northern Great Plains, Uinta, Piceance and some other western basins. The NPC Task Group presumed that five western pipelines would be operational by 1984, and stipulated that eight additional pipelines would be required to carry tight sands gas to markets in the 1984-2000 period. Two of these pipelines are in the Northern Great Plains/Williston region, while the remaining six are needed in the Rocky Mountain region.

Argonne undertook its own assessment of the accessibility of the twelve western basins to the existing and proposed pipeline network. The results of this assessment, although not published, are summarized here.[7] Basically, in order to investigate the pipeline accessibility of the basins, detailed maps were prepared that identified the basin locations and the existing and proposed pipeline routes. A determination was made of the degree of difficulty and the cost of linking the basins to the adjoining interstate and intrastate pipeline network. Once this task was accomplished, an investigation of available capacity in the system was performed. This investigation consisted of comparing various outputs of the GASNET Model - a general equilibrium model of the natural gas pipeline system structured with links and nodes - corresponding to different Department of Energy/Annual Report to Congress and National Energy Plan scenario projections of natural gas supply and demand.

The results of this comparative analysis of pipeline flow and capacity simulations are summarized in the following conclusions. First, the pipelines contiguous to the tight sands gas basins in the Rocky Mountain and Northern Great Plains regions are small in capacity relative to the current and potential volumes of gas available. This may introduce delivery problems if the other gas resources in the area continue to expand their production without new pipeline capacity. Second, the existing pipeline network is presently only redistributing intrastate and some interstate gas within the Northern Great Plains and Rocky Mountain regions. Both of these regions have not historically been major natural gas regions supplying the entire country, therefore their pipeline system is not interconnected with the principal demand regions. Finally, the existing interstate pipelines transecting the Rocky Mountains region have flow patterns that are principally in a northwesterly direction, away from the major supply fields in New Mexico and western Texas. This pipeline orientation will not readily accommodate the intermingling of tight sands gas for eventual delivery to the West Coast and Midwest. However, it will facilitate tight sands gas delivery to the Pacific Northwest. In addition, the only major interstate pipeline in the Northern Great Plains region has a southeasterly flow and presently could only supply tight sands gas to the Midwest, if interconnections were made with the tight sands formations of this region.

8.1.1 Regional Pipeline Accessibility

The tight sands gas basins in the Southwest region are located in Texas and New Mexico. Due to the density of intrastate and interstate pipelines originating in the Texas gas fields, all four tight sands gas basins in this region have access to major gas transmission lines. Besides ready access, pipeline capacity is also expected to be available. The projected future production from conventional Texas gas fields is expected to decline, making pipeline capacity that can be filled with tight sands gas more available.

In the Northern Great Plains/Williston region, only one major interstate transmission line is presently accessible. The eastern leg of the Alaskan Natural Gas Transportation System (ANGTS), called the Northern Border Pipeline, bisects the eastern sections of the Williston Basin in North Dakota. Consequently, particular formations, such as Niobrara, may have more direct access to this interstate pipeline than other Northern Great Plains formations. Construction of extensive gathering and feeder lines to link the tight gas sands wells to the pipeline will be required. This will be an expensive undertaking, but the extensive resource base and the relatively lower priced extraction cost grades in the Northern Great Plains region may make this linkage very advantageous for both producers and consumers.

Furthermore, delay of the northern segments of ANGTS, in conjunction with possible reductions in Canadian gas exports for national security reasons and declines in gas shipments due to demand responses to export price increases, would make capacity in the Northern Border Pipeline available for tight sands gas supplied from this region. Needless to say, this is only one pipeline with a current capacity of 800 million standard cubic feet per day (MMCF/D). Several more pipelines would need to be constructed in order to increase (1) accessibility to the other tight sands formations in this region, and (2) deliverability of the extensive resources available. Because of the extensive land area (33,000 mi^2), a massive gathering and feeder line system would still be required to link the production wells to these additional pipelines.

The pipelines that exist within the Rocky Mountain region are primarily intrastate. Where the transmission lines are interstate in nature, they principally transport gas to adjacent states. The two exceptions to these conditions are the El Paso Natural Gas and the Colorado Interstate Gas pipelines.

Through an examination of reported industry-specific contracts for future gas supplies and past sales patterns it has been determined that most intrastate and interstate pipelines in the Rocky Mountain region will require reserve additions to supplement their supply base.[7] It was found that these pipelines exhibit a sales pattern of constant or increasing demand for natural gas while their reserve-to-delivery ratio (i.e., sales-life index) is declining. Tight sands gas is a highly prospective resource that is located in close proximity to these pipelines and, thereby, can supply the natural gas required to satisfy the pipeline demand contracts. However, new interstate pipelines will also need to be constructed in order to transport the tight sands gas to interregional demand markets. There is currently very little excess capacity in these interstate pipelines.

Almost all of the Rocky Mountain tight sands gas basins have some degree of access to existing and proposed natural gas pipelines. However, upon review of Fig. 20, and other maps not presented here, it is obvious that only particular portions of these basins could be considered to have pipeline accessibility. Existing and proposed pipelines intersect with these basins, but often constrain accessibility due to their route. These routes limit the general accessibility of the whole basin to the pipeline(s), since the size of these land areas prohibits the construction of extensive gathering and field lines. The only basin that is/will be more comprehensively covered by major transmission lines is the Denver Basin (see Fig. 20).

8.1.2 Proposed Pipelines

Besides the present pipelines in the Rocky Mountain region, five new interstate pipelines are either proposed or under various stages of development. These new pipelines will link the gas resources, and particularly the tight sands gas resources, of the Rocky Mountain area to the primary demand

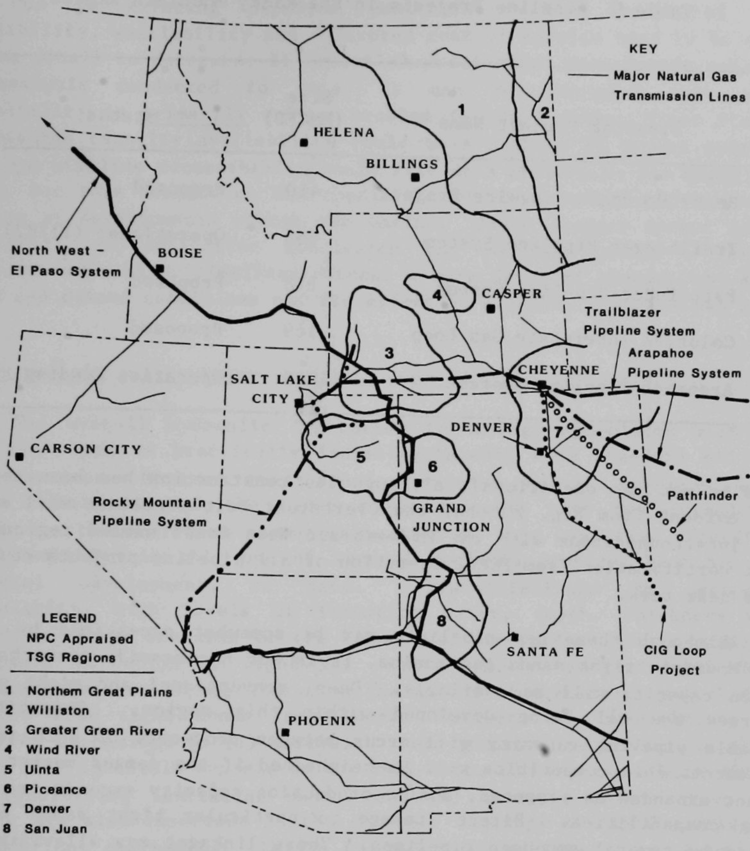

Fig. 20 Planned and Proposed Overthrust Belt Pipelines Accessible to the Rocky Mountain Tight Sands Gas Basins

regions. The pipeline projects are listed in Table 9 and their routes identified in Fig. 20.

The Rocky Mountain Pipeline Project is still in the planning stages and undergoing supply contract negotiations. It is the only new pipeline that will connect the Rocky Mountain basins to the West Coast. The remaining four pipelines all have an eastern orientation. The Trailblazer System is currently initiating operation, while the Pathfinder has filed for a revision to its initial route, so that it would now originate in the Wind River Basin (Wyoming). The Colorado Interstate Loop has been competing with the Pathfinder Project for certification; its status is uncertain. The Arapahoe

Table 9 Pipeline Projects in the Rocky Mountain Region

Pipeline Project Name	Size (MMCFD)	Status
Rocky Mountain Pipeline Project	410	Proposed
Trailblazer Pipeline System	665	Operational (11/82)
Pathfinder Pipeline System	175	Proposed
Colorado Interstate Gas Loop	169	Proposed
Arapahoe Pipeline System	185	Operation Pending

System is not yet operational, although its construction has been completed. It is evident from Fig. 20 that the Overthrust Belt pipelines will establish major interconnections with the Midwest and West Coast demand regions. With prompt certification from FERC, operation of all pipeline projects could occur in the near term.

Although these new pipelines may be somewhat accessible by the five Rocky Mountain tight sands gas basins, it is not necessarily true that transmission capacity will be available. Deep, conventional and tight sands gas resources are all being developed within this region. Competition for available pipeline capacity will occur between producers of each respective gas source. This competition will be heightened if the demand market linkages are not expanded as proposed, and/or production capacity exceeds transmission network capabilities. Direct linkage to particular tight sands basins is planned by several proposed pipelines. These linkages may alleviate some of the commercial development risk cited by producers as a reason for not developing the tight sands gas basins more aggressively.

The Southwest and Northern Great Plains regions have no presently identified proposed pipelines according to FERC records.

8.1.3 Summary

Pipeline accessibility to the three tight sands gas regions is summarized above. A qualitative rating of pipeline accessibility by basin appears in Sec. 8.3. It has been indicated that (1) access to basins varies between regions and within regions according to where the pipeline transects the basin and (2), although basins may have access to existing and proposed pipelines, the availability of transmission capacity may not exist in the near term due to existing pipeline contracts. The issues of pipeline accessibility, availability and delivered cost of service need to be addressed in more detail to determine if potential development constraints exist. From the analysis conducted to date, it can be concluded that near-term accessibility is primarily only a problem in the Northern Great Plains, but transmission capacity availability could be a problem in almost every basin. Near-term pipeline accessibility could also be a problem in the Rocky Mountain basins, but this depends on the completion of the proposed pipelines and the location of developments within the basins. Given present market conditions (1982-1983), no definitive conclusion can be made about a development constraint imposed by pipelines without a more detailed examination of future supply and demand conditions and its effect on pipeline transmission capacity.

8.2 TECHNOLOGY AVAILABILITY TO HANDLE SPECIAL GEOLOGIC PROBLEMS

The overall hydraulic fracturing technology associated with blanket tight sands gas is practically indistinguishable from standard oil and gas field practices. However, there are some special geologic problems that arise in the development of the tight sands resource that may introduce some barriers to the near-term commercialization of this resource. Specifically, low permeability is only one of several geologic problems that has limited commercial development, to date. Discontinuities in permeability, lenticularity, high levels of formation water, depth, thickness and the presence of clays are some of the other geologic factors that complicate the development potential of tight gas sands. Hence, geologic and reservoir characteristics can impose limits on the amount of commercial gas that can be recovered from tight sands formations. Further, the adaptability of the fracturing technology to (1) deal with these geologic problems, (2) stimulate all gas zone intervals exposed to the well bore, (3) intersect with all lenses (when considering lenticular sands) and (4) maintain an effective propped fracture are also important in the economic recovery of tight sands gas from the formations and basins. In the following subsections, some of the special geologic problems are highlighted for each basin and region, and an assessment is made of the adaptability of the technology to deal with these problems. A qualitative rating of technology adaptability appears in Sec. 8.3 for each basin.

8.2.1 Status of Technology

Before the region-specific discussion of geologic problems is presented, some general statements are made regarding technology availability. First, improved measurement capabilities are needed to accurately determine a variety of reservoir characteristics in tight sands formations. For example, better diagnostic technology to obtain detailed information on the characteristics of formations such as permeability, gas-filled porosity, net pay thickness and *in situ* rock properties and stresses would enhance the fracture design techniques for reservoir stimulation. Reliable data for these characteristics are generally important for determining the amount of gas contained in the reservoir, the expected well output rates, and the costs of producing the gas. The Electric Power Research Institute performed an evaluation of the constraining impact on gas production of these resource characterization factors and found that they generally caused a major constraint through 1983, and an insignificant effect after 1984-1987 (depending on the formation type). Further, "in all cases the indicated constraints to gas production are associated with risks to producers resulting from inadequate technologies for characterizing the resource."* Improvements in these resource characterization technologies would reduce such uncertainties and hence, risks to tight sands formation producers.[42,43]

Uncertainties in resource characterization and the measurement technologies affect the second area of technology availability, hydraulic fracturing. Development of tight sands gas production procedures requires refinement and experimentation when entering a new resource area. To properly design the new stimulation procedures, better diagnostic technologies are required to acquire the detailed characterizations of the formation. Moreover, to prevent potential stimulation problems, a better prediction of fracture geometry and more control over the application of the fracturing techniques are necessary. To date, industry attempts to design and perform massive hydraulic fracture (MHF) have often been done with limited information on specific well characteristics (e.g., measurement of height away from the well bore, and measurement of fracture width and length). Therefore, advancements in hydraulic fracturing techniques and improved reliability in reservoir measurement will enhance the economic attractiveness of the tight sands resource, reduce the inherent development risks and increase producer knowledge of basin-specific problems.[43]

Despite these comments on the potential for improvements, hydraulic fracturing technology represents the current state-of-the-art for recovering natural gas from tight formations. This technique is practiced largely in the more geologically favorable blanket formations.** The general performance and reliability of MHF has been discussed in Sec. 5. There still remain some potential constraints to its application to certain blanket sands formations with special geologic problems. Increased production, lower costs and reduced uncertainties would result from hydraulic fracturing technology improvements. The Electric Power Research Institute identified the hydraulic fracturing technology as a major constraint in blanket formations through 1986 (for the poorer cost grades) and an insignificant constraint after the year 1990 (for the same cost grades).[42,43]

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*Ref. 42., p. 2-4.

**Further improvements in the hydraulic fracturing technology are required to achieve the same degree of success in lenticular sands formations.

Two conclusions can be drawn from this summary. First, the technologies to determine resource characteristics and reservoir parameters are still somewhat under development and experimentation, but should not present a major constraint to tight sands development after the mid 1980s. Secondly, the technologies to evaluate, stimulate and recover the tight sands gas are readily available for tight blanket formations, with no major constraints for the better cost grades beyond the present time (1982). However, although the hydraulic fracturing technology is available for tight blanket sands, there remain some special geologic problems in particular basins that need to be resolved. Some of these problems are described in the following subsections.

8.2.2 Northern Great Plains Region

The gas potential in the Northern Great Plains tends to be stratigraphically controlled, although some structural trapping is present, such as a moderate dome or a fault. Structural trapping often results in better tight sands gas deposits called "sweet spots."

All the blanket formations in Northern Great Plains region are shallow. However, it is useful to divide these formations into two groups. Niobrara in the eastern part of the region is deeper (i.e., about 2700 ft) and higher pressure (1150 psia) than the other formations in the region. Also, Niobrara is a limestone formation which responds better to hydraulic fracturing.

The other formations in the region are Mowry, Carlile, Eagle, Greenhorn and Judith River. These formations tend to be predominantly shale and clay in nature. Embedded in the massive shale and clay intervals are silt and siltstone stringers, which often have gas potential. These stringers are pencil-like lenses or microlaminations. When a well is drilled, it may be difficult to identify the pay zone because the stringers are hard to detect on gamma ray and spontaneous potential (SP) logs. Further, the shale and clay tend to be elastic and absorb fracture energy. The shallowness of these formations causes the desired vertical orientation of the fracture to be somewhat less reliable. Also, the low pressure requires gas compression in the field. Although it is expected that about 100 TCF of gas is recoverable from Northern Great Plains, the range of estimates varies substantially.[6] In addition to these problems, there remains the question of whether the origin of this gas is biogenic or thermally controlled.

In the NPC analysis of this region, a ball sealer technology was asssumed to be used to simultaneously fracture multiple overlapping formations. There are numerous overlapping formations in this region; sometimes the number of fracture layers reaches as high as five, but most of the resource would require the simultaneous fracturing of two to four layers. However, the greater the number of overlapping formations, the more difficult this technology is to apply. In addition, fracture lengths may become uneven between the different layers.

For the reasons discussed above, the resource in the Niobrara formation is ranked higher for near-term development than the resource in other formations within Northern Great Plains (see Sec. 8.3). The availability of technology to identify and recover the tight sands gas from stringers and multiple layers is still under development.

8.2.3 Rocky Mountain Region

The blanket sands formation characteristics in the Rocky Mountain region differ somewhat between each other. The Frontier/Muddy formation in the Wind River Basin is shallow. Corcoran-Cozette in the Piceance Basin is intermediate in depth (6000 ft). The Denver Basin gas potential is found at about 8000 ft. The Almond A formation in the Greater Green River Basin is deep at 10,000 ft. The deeper rock formations in this region respond well to fracturing because they tend to break up rather than absorb the fracturing energy.

The major tight sands gas activity by Amoco in the Wattenberg field of the Denver Basin is not considered here, even though they have been very successful with the application of hydraulic fracturing technology in this basin. The NPC assessment of the remaining undiscovered resource in the Denver Basin shows only the very poor resource left undiscovered. There has been considerable tight gas sands activity in Uinta Basin, Piceance Basin and more recently, in the Greater Green River Basin. However, the following geologic conditions present challenging technological problems; Greater Green River Basin - presence of clays; Piceance Creek Basin - substantial lenticular sands; Wind River Basin - very different characteristics for lenticular and blanket formations; and Uinta Basin - high water saturation. These basin-specific problems result in their lower rating of technology adaptability presented in Sec. 8.3.

8.2.4 Southwest Region

In the Southwest, the Cotton Valley and San Juan basins are currently producing tight sands gas. Cotton Valley is a deep formation with a large area of prospective gas potential. Edwards Lime Trend is very deep and water saturation is particularly severe. In the Val Verde Basin, some well completions in tight gas sands have been made, but with uneven results. The pore throat structure of the blanket sands in this basin may lead to very poor permeability. The geologic problems of water saturation in Edwards Lime Trend and the permeability problems in Val Verde Basin have no present near-term technology solution. These problems cause their lower ranking in terms of technology adaptability (Sec. 8.3).

8.3 RANKING OF TIGHT SANDS GAS BASINS WITHIN THREE WESTERN REGIONS

Now that the other two aspects of tight sands gas development potential (i.e., pipeline accessibility and technology adaptability) have been examined, the basins can be rated according to their capability for development. The barriers, impediments and economics confronting each basin are incorporated into the ranking.

Table 10 presents the comparison of extraction costs, recoverable resource, pipeline accessibility and the state of fracturing technology for the blanket sands formations. Three extraction cost levels are presented with the following associated conditions: 1000-ft average effective fracture length, 15% discount rate and both the constrained and unconstrained well-spacing cases. The estimated recoverable resource at the three extraction costs can be interpreted as the potential blanket sands gas available by basin at each minimum required selling price presented. This table is arranged so that the basins can be compared and contrasted within a specific region. The ranking and rating of basins was performed within each of the three regions. No attempt is made here to compare basins between different regions. One reason why this would be difficult is that over 80% of the blanket resource in the Southwest is not appraised in detail by the NPC study. Another reason is that the geology types for the tight sands deposits and the technical problems for each deposit are different between regions. Therefore, cross-regional comparisons may not be as accurate because of these reasons and particular assumptions and conditions of the study regarding fracturing technology adaptability and economics, and pipeline accessibility. A qualitive rating of these two development factors is provided in Table 10. An interpretation of the scale is found in the footnotes.

In the Northern Great Plains region, the Niobrara formation and overlapping Niobrara and Carlile formations are separated from the other Northern Great Plains (NGP) formations because of their differences in geology and therefore, development potential (see Sec. 8.2.1). The Niobrara formation is deeper and responds better to hydraulic fracturing. Furthermore, it is in the eastern portion of the region and has greater accessibility to the Northern Border Pipeline. For these reasons its development capability rating, identified in Table 10, is higher than that of the other NGP formations. Although these remaining NGP formations have the predominance of the estimated recoverable blanket resource, the problems of depth, pressure and origin described in Sec. 8.2.1 may affect the quantity of ultimately recoverable blanket tight sands gas. Moreover, the absence of major interstate pipeline interconnections may further impair the near-term development potential of these other formations. However, this region has the greatest quantity of the lower cost grade resource, together with the greatest regional quantity of total recoverable resource, thereby maintaining its high attractiveness for development. The possible barriers previously specified may impair near-term development, but future development of this whole region is imminent. Pipeline accessibility is only a temporal problem; development of a tight

Table 10 Comparison of Extraction Costs, Recoverable Resource, Pipeline Accessibility and State of Technology for Tight Sands Gas Basins in Three Western Regions[a]

	Recoverable Blanket Resource (in TCF) Available at a Given Extraction Cost: 1000 ft Fracture, 15% Discount Rate, Constrained and Unconstrained Well Spacing Case						Qualitative Development Capability Rating	
	$4/MCF[b]		$6/MCF		$10/MCF			
Basins/Formations	CON[c]	UNCON[d]	CON	UNCON	CON	UNCON	Accessibility to Pipelines[e]	Blanket Sands Technology Adaptability[f]
Niobrara, Niobrara and Carlile Formations	9.04	9.47	9.38	10.55	9.38	10.55	B	A
All other NGP Formations	56.28	59.94	67.14	79.28	71.70	86.48	C	B
Northern Great Plains/ Williston Basin Region Total	65.32	69.41	76.52	89.83	81.08	97.03		
Uinta	4.14	4.20	4.28	4.46	4.48	4.78	A	B
Piceance Creek	2.10	2.10	3.03	3.61	3.03	3.61	A	B
Greater Green River	2.09	2.09	8.40	8.58	9.62	10.10	A	B
Wind River	0.89	0.97	1.11	1.38	1.16	1.55	B	B
Denver	-	-	-	-	-	-	A	A
Rocky Mountain Region Total	9.22	9.36	16.82	18.03	18.29	20.04		
Cotton Valley	5.39	5.39	6.52	7.11	6.98	8.35	A	A
Edwards Lime Trend	2.15	2.35	6.22	7.01	6.71	8.06	A	B
San Juan	0.46	0.46	1.49	1.49	1.49	1.49	A	A
Val Verde (Ozona & Sonora)	-	-	0.79	1.64	0.84	1.98	A	B
Southwest Region Total	8.00	8.20	15.02	17.25	16.02	19.88		
Grand Total	82.54	86.97	108.36	125.11	115.39	136.95		

[a]The tabular results include only basins and subbasins appraised in detail by NPC. Only undiscovered tight sands gas was appraised in the NPC study. Also excluded are substantial proved reserves in the Denver, San Juan and Cotton Valley Basins.

[b]Mid-year 1981 dollars.

[c]Constrained Well Spacing Case, 4 Wells/Section.

[d]Unconstrained Well Spacing Case, Maximum Recoverable Resource.

[e]Pipeline Accessibility Key: A = Readily accessible or minor linkages required, B = linkages required, C = Unaccessible without substantial development.

[f]Blanket Technology Adaptability Key: A = Technology adaptable with minimal difficulty, B = Geologic problems may prolong the adaptation of the technology.

sands gas field and gathering network would take time to construct, but would not seriously affect the relative economic attractiveness of this region. Moreover, industry experience may eliminate most of the uncertainties pertaining to the geology and fracturing of the other NGP formations.

In terms of recoverable blanket sands resource appraised by NPC, the Rocky Mountain region is second (Table 10). The amount of recoverable blanket sands gas potentially available is only marginally greater in the Rocky Mountains than in the Southwest region. However, less than 20% of the recoverable tight sands gas in the Southwest region was appraised by NPC. Table 10 may present a different picture if this excluded resource was incorporated in the recoverable resource of the Southwest region. Moreover, the pipeline and technology constraints to development are less serious in the Southwest basins.

Presently, the Rocky Mountain basin with the greatest amount of recoverable blanket tight sands gas and the best rating, in terms of pipeline accessibility and technology, is the Uinta Basin. This basin contributes almost one-half of the Rocky Mountain region recoverable blanket resource. However, the Denver Basin has been the most active in terms of industry experience and drilling activity. Because most of the economically recoverable blanket sands gas in this basin has been classified as proved reserves, it was excluded from consideration in the NPC study. Only undiscovered tight sands gas was appraised by the NPC Task Group, and the remaining recoverable resource in this category for the Denver Basin has an extraction cost greater than $10.00/MCF. Therefore, it provides no resource to the regional total in Table 10.

By far the best near-term basin in the Southwest region is the Cotton Valley Basin. It has more than two-thirds of the recoverable blanket sands resource in the region, without considering the substantial proved reserves excluded from this basin in this study. It also has one of the best development capability ratings. However, the dominance of recoverable blanket resource within the region is confined to the lowest extraction cost considered ($4.00/MCF). At the higher extraction costs the Edwards Lime Trend Basin contributes almost as much recoverable resource. The present technological drawbacks to development of the Edwards Lime Trend include the previous difficulties encountered in fracturing and the problem of water saturation on this reef trend.

8.4 UNDISCOUNTED INCREMENTAL BENEFITS RESULTING FROM TECHNOLOGICAL AND REGULATORY IMPROVEMENTS IN THE DEVELOPMENT OF BLANKET TIGHT SANDS GAS

The previous subsections have discussed potential barriers to the development of tight sands gas and regionally ranked the basins according to their development potential. Furthermore, earlier sections of this report examined the minimum undiscounted benefits that may accrue from either technology advancement <u>or</u> changes in well-spacing regulations. In this subsection, the benefits from improvements in technology and regulatory conditions are simultaneously determined and quantified.

Table 11 presents the results by basin and region of the simultaneously determined undiscounted incremental benefits. The results are incremental because they are presented relative to a base case - a 1000-ft average achieved fracture length and a limit of 4 wells per section. Consequently, these undiscounted benefits are not the total undiscounted benefits from the development of the tight sands gas basins under some specified conditions, but are only the undiscounted benefits that would accrue from an improvement in development conditions, i.e., an increase in average achieved fracture length from 1000 to 1200 ft and/or a relaxing of the well-spacing regulations from the constrained case (4 wells per section) to the unconstrained case (no limit). Three discrete wellhead price levels are presented with a 15% real rate of return.

The important conclusion from this table is that the effects of longer fractures and relaxed well-spacing constraints are not entirely independent. Table 11 presents the undiscounted incremental benefits for both these factors separately and in combination. It is found that the effect of a fracture length improvement is often much greater than a change in the well-spacing constraint. However, the magnitude of difference varies by basin and between regions, and most importantly by extraction cost level. At higher wellhead price levels (i.e., \$10.00/MCF), the undiscounted benefits from a relaxation in the well-spacing constraint were greater than those for a technology improvement in particular basins. The undiscounted benefits from a fracture length change were always greater, however, at the lower extraction costs (i.e, \$4.00/MCF).

The greatest undiscounted benefits from these two improvements in development conditions accrue in the Northern Great Plains region. A total of \$119.8 billion in undiscounted benefits would result from a fracture improvement and a relaxation of the regulatory requirements. This benefits level is contrasted with \$18.4 and \$26.7 billion for the Rocky Mountain and Southwest regions, respectively. Needless to say, a substantial quantity of undiscounted benefits can be derived from the simultaneous improvements in fracture technology and well-spacing conditions (i.e., \$164.9 billion).

Table 11 Undiscounted Incremental Benefits Resulting from Fracture Efficiency/Predictability Improvements and Relaxed Well Spacing Regulations in Twelve Western Tight Sands Gas Basins[a,b,c]

Basins/Formations	Fracture Length (Feet)	Undiscounted Incremental Benefits Indicated Relative to the 1000 ft Fracture, Constrained Well Spacing Case (Billions of 1981$)					
		$4.00/MCF[d]		$6.00/MCF[d]		$10/MCF[d]	
		CON[e]	UNCON[f]	CON	UNCON	CON	UNCON
Northern Great Plains/ Williston Basin Regional Total	1000	–	6.4	–	26.0	–	87.0
	1200	18.4	24.3	28.3	53.5	43.2	119.8
Uinta	1000	–	0.1	–	0.2	–	1.0
	1200	1.3	1.3	1.6	1.6	2.2	2.9
Piceance Creek	1000	–	0.0	–	0.7	–	3.1
	1200	1.1	1.3	1.5	2.3	2.1	4.7
Greater Green River	1000	–	0.0	–	0.0	–	0.9
	1200	1.3	1.3	4.9	5.0	6.8	7.5
Wind River	1000	–	0.1	–	0.5	–	1.8
	1200	0.4	0.3	0.7	1.0	1.2	2.4
Denver	1000	–	0.0	–	0.0	–	0.1
	1200	0.0	0.0	0.0	0.0	0.6	0.9
Rocky Mountain Region Total	1000	–	0.2	–	1.4	–	6.9
	1200	4.1	4.2	8.7	9.9	12.9	18.4
Cotton Valley	1000	–	0.0	–	1.1	–	6.1
	1200	2.3	2.4	2.9	4.2	4.2	10.0
Edwards Lime Trend	1000	–	0.3	–	1.3	–	4.8
	1200	2.4	2.7	3.6	4.6	5.5	9.7
San Juan	1000	–	0.0	–	0.0	–	0.0
	1200	0.2	0.2	1.0	1.0	1.0	1.0
Val Verde (Ozona & Sonora)	1000	–	0.0	–	0.8	–	4.4
	1200	0.0	0.0	0.6	1.9	1.1	6.0
Southwest Region Total	1000	–	0.3	–	3.2	–	15.3
	1200	4.9	5.3	8.1	11.7	11.8	26.7
Grand Total	1000	–	6.9	–	30.6	–	109.2
	1200	27.4	33.8	45.1	75.1	67.9	164.9

Table 11 (Cont'd)

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[a]The tabular results include only basins and subbasins appraised in detail by NPC. Only undiscovered tight sands gas was appraised in the NPC study. Also excluded are substantial proved reserves in the Denver, San Juan and Cotton Valley Basins.

[b]Improvements in technology reduce extraction costs of already economic resources and increase the quantity of economic resources. This table includes both types of benefits.

[c]The calculated benefits measure only a portion of the total undiscounted benefits derivable from fracture related R&D programs. The benefits here focus on pure technical progress as measured by longer average achieved fracture lengths for a given fracture design. The fracture design in the NPC base case has a hydraulic length of 1666 feet. The average length increases either due to improved efficiency in sand transport or better predictability of fracture performance. Not included are benefits which should result from the feasibility of substantially larger fracture designs, of say 4000 ft. Also, benefits accruing to tight gas basins other than the twelve appraised in the NPC study are not included.

[d]Definition of economic resources: Wellhead price in midyear 1981 dollars sufficient to earn at least a 15 percent real rate of return.

[e]Constrained Well Spacing Case, 4 wells/section.

[f]Unconstrained Well Spacing Case, Maximum Recoverable Resource.

9 CONCLUSIONS

From the analysis undertaken in this study, many important conclusions are apparent for both the near-term and longer-term development of blanket tight sands gas. In reviewing the conclusions as summarized below, the conditions of the study should be kept in mind, e.g., which resources are included in the NPC *Tight Gas Reservoirs* data base and which are excluded (see Secs. 1 and 2).

- *Substantial blanket tight sands gas is available.* In this study it was estimated that approximately 130 TCF of economically recoverable gas remains to be discovered in the twelve NPC appraised basins. These appraised basins represent about 35% of the prospective area thought to contain natural gas in the lower 48 states.

- *Enforcement of current well-spacing regulations would substantially reduce the available tight sands gas.* A limit of four wells per section reduces the economically recoverable blanket gas by about 20 TCF in the twelve appraised basins, to a total of 110 TCF. Evaluated at a $6.00/MCF real wellhead price of gas, relaxation of these well-spacing regulations would result in approximately $30 billion (midyear 1981 dollars) of benefits (undiscounted).

- *Profits are available in the exploration and development of blanket tight sands gas resources.* For example, if one expects a real wellhead gas price of $3.50 and extraction costs are $2.50, then some additional income is generated. The additional income is shared by the producer, royalty holder and taxing agencies. The producers' share of this income is reported as profits in the year that the gas is produced and, hence, does not represent present value profits at the time of initial exploratory drilling. The present value of profits depends on the production profile from the field, the net revenue stream and the discount rate. Of course risks are present, and profits cannot be guaranteed, but extraction costs are computed to include a compensation for the producer taking risks.

- *The development of blanket tight sands gas can potentially lower gas rates to consumers.* In this study, blanket tight gas resources were sorted in order of extraction cost and plotted as a function of cumulative resource stock. These curves are called "resource supply curves" or "marginal cost curves." Substantial resources appear to be available in the $2 to $3 range. When this resource is included in energy sector analyses and forecasts over the next 10 to 20 years, market gas prices, and hence the rates consumers need to pay, may be reduced.

- *During the last decade hydraulic fracturing technology has greatly advanced.* For example, Argonne estimated, from well performance data during the mid to late seventies, that the fracture design parameters assumed in the NPC *Tight Gas Reservoirs* study would produce an average achieved fracture length in the range between 600 ft to 800 ft. Current technology probably will achieve about 1000 ft on average, with a created hydraulic design length of 1700. With continued technical progress, the average achieved length could increase to 1200 ft.

- *For resources which are already economic, improved fracturing technology reduces extraction costs, particularly for the poorer permeability grades.* For an increase in the effective fracture length from 1000 ft to 1200 ft (with the same fracture treatment cost budget) extraction costs decrease on average 13.5%. However, extraction costs for the poorer permeability grades decrease 20% to 25%. For the better (i.e., near tight) resource grades, extraction costs decrease 10%. For these near tight resources, improved fracturing may not increase ultimate well recovery, but the rate of well production will increase, improving the well payback period and the net present value of profits.

- *Improved fracturing technology increases more blanket tight sands gas availability.* Given the wellhead market price of gas, improved technology will cause some resources which were not economic at the market price to become economically recoverable.

- *The benefits of tight sands gas R&D are very large.* At a market price of $6.00/MCF, the undiscounted benefits of an increased average achieved fracture length from 1000 ft to 1200 ft is $45 billion (midyear 1981 dollars), in just the 12 basins appraised by NPC.

- *Risk premiums significantly affect extraction costs.* In this study the effects of risks (e.g., commercial, technical, geologic, and regulatory risks) are represented as a risk premium included in the required rate of return. Suppose that through risk reduction the required rate of return changes from 15% real to 10%. Then, extraction costs on average decrease 25%.

- *The effects of learning can improve technology and reduce risks simultaneously.* For example, a more reliable MHF technology both increases the average fracture length as well as reduces risk. An average fracture length change from 1000 ft to 1200 ft, together with a reduction in required rate of return (risk premium) from 15% real to 10%, yields a 35% reduction in extraction costs.

- *Argonne has devised a simple, straightforward methodology to determine the effects of improved fracture technology on extraction* *costs and undiscounted benefits.* The ratio of improved to current extraction costs is given by the ratio of the present value gas production streams computed using both current and improved well production. Well production as a function of fracture length is derivable from graphs called "type curves."

- *The basins analyzed here are heterogeneous, affecting near-term development prospects.* For example, Northern Great Plains looks attractive due to the large estimated size of the resource and the low cost of drilling wells into shallow formations. However, the tight sands gas in this basin is difficult to detect and in general, relatively more risky to develop due to limited experience in this basin. The entire Northern Great Plains region was appraised by NPC. In contrast, only 20% of the Southwest region, where substantial drilling activity currently exists, was appraised in detail by NPC.

- *There are many tight gas sands basins accessible to existing gas pipelines.* The Southwest and Rocky Mountain basins are served by pipelines. However, access to pipelines in Northern Great Plains is a problem. The location of the existing and proposed pipelines within each region and basin may require the development of an extensive field and gathering system, and the construction of new interconnecting pipelines. Otherwise, particular formations and basins would have only limited accessibility to a transmission system for the tight sands gas.

- *Additional factors are needed to accurately rate the development potential of the twelve Western Tight Gas Sands Basins.* Within each region, Argonne ranked the basins appraised by NPC according to three factors: extraction cost, pipeline accessibility and technology adaptability. Some clear distinctions can be made between particular basins in each region. In particular, the Niobrara formation and the overlapping Niobrara and Carlile formations in the Northern Great Plains region are more capable of near-term development than the other formations in this region. Better pipeline accessibility and technology adaptability are key factors. Within the Rocky Mountain region, the Uinta, Piceance and Greater Green River basins all have favorable development factors, although the Uinta Basin contributes around one-half of the economically recoverable resource in the region. In the Southwest region, the Cotton Valley Basin is by far the best basin for near-term development for all factors considered in this study. The San Juan Basin has favorable development potential using a recompletion technology, but does not have a substantial quantity of recoverable resource appraised by NPC. Beyond this regional ranking, additional detail and more factors are required before this rating could be used to fully analyze a drilling program.

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APPENDIX A
REVIEW OF THE NATIONAL PETROLEUM COUNCIL (NPC) *TIGHT GAS RESERVOIRS* STUDY

The NPC *Tight Gas Reservoirs* study is extensive in scope, and encompasses the following areas:

- Geologic and cost data for tight gas sands.
- Economically recoverable tight sands gas resource at several prices.
- Several tight sands gas field development and production scenarios.
- Demand, pipeline, regulatory, protected area and other constraints to tight gas development.
- A tight gas sands R&D agenda.

The compilation and analysis of data in these areas were ambitious undertakings. The NPC study now provides a foundation for future analysis of tight sands gas.

This report focuses on the second item: the quantity of recoverable tight sands gas resource as a function of price.

The NPC task group appraised twelve basins in detail. The geologic data were collected and the economic analysis performed for subbasins called study areas (SAs). Study areas are defined for each prospective tight sands formation in a given basin, and separate SAs are defined for areas where the gas potential of two or more formations overlap. In fact, each combination of these overlapping formations is treated as a separate SA. Eighty-two study areas were analyzed in the NPC report. In this Argonne report, 38 SAs containing blanket formations are analyzed. These SAs and their associated formations are listed in Table D.1 of Appendix D.

This appendix reviews the basic assumptions underlying the NPC methodology for calculating the quantity of tight sands gas available at a given price. Some of the assumptions are needed to model situations that are quite complicated. Given the difficulty of the task, the NPC study is a carefully designed large-scale modeling effort. Key assumptions underlying the economic analysis are delineated and discussed below.

1. *The resource in each study area (SA) is classified by a set of permeability levels (k-level). Net pay thickness and gas-filled porosity are functions of k.*

First, the resource is classified by its average permeability k. Then the relationships between k and average pay thickness h and average gas-filled porosity ϕ are estimated. Only one value for h and one value for ϕ are associated with each k-level. These representative reservoir characteristics are used in predicting well production, as described in Appendix C.

2. *Estimated quantities of gas-in-place by SA and k-level are taken to be known parameters for the economic assessment.*

NPC geologic teams analyzed each basin in detail. The productive areas in sections (mi^2) associated with each SA and k-level were estimated. For each SA/k-level, the corresponding average values for h and ϕ were used to estimate gas-in-place.

3. *Maximum recoverable gas is adjusted downward to reflect actual variability in reservoir properties.*

Actual permeability k varies in horizontal and vertical directions. Also h and ϕ vary for any given k. Recovery factors are applied to compute the maximum recoverable gas from the gas-in-place. The recovery factors for blanket sands range from 70% to 95%, with the larger recovery factors associated with higher permeability reservoirs.

4. *Each tight gas field is composed of a single k-level. Field size (BCF of gas) is described by a probability distribution, depending on the basin and k-level.*

Because only one k-level is allowed per field, fields may be smaller in the NPC analysis than if more complex fields were allowed with multiple k-levels. In the NPC analysis, the overall average field size is about 20 BCF of gas. Also it may be difficult to distinguish between actual new field wildcats and wildcats stepping out from existing fields into different k-levels. In some basins the wildcat success ratio is over 50%.

In blanket tight gas sands that often have stratigraphic rather than structural control, reservoir boundaries may not be as well defined as in conventional gas pools. Blanket sands contain continuous gas-bearing rock with occasional "sweet spots" of better permeability separated by areas of very poor permeability. If it is economic to develop both the sweet spots as well as the adjoining poorer permeability deposits, then new fields (i.e., different k-levels) may be discovered in the process of developing an existing field. Also, wildcat drilling into these adjoining k-levels may not be independent of previous drilling (i.e., the probabilities of finding various k-levels by a step-out wildcat may depend on the k-levels of nearby discovered fields). Assuming independence between wildcats is much easier to model.

5. *The number of development wells is based on the required number to drain the reservoir in 30 years.*

Based on field size and 30-year ultimate recovery per productive well, the required number of wells can be computed. The average number of productive development wells varies by basin from about 5 to 20 wells per field. A uniform 20% dry hole rate is assumed for development wells. Note that under some circumstances drilling more development wells with closer spacing may extract the gas faster and increase profits.[44,45]

6. *The recoverable resource may be limited by well-spacing regulations.*

In the NPC base case, a maximum of four productive wells per section is allowed. This constraint approximates actual limitations as determined by the regulatory process in state oil and gas conservation agencies. In the advanced case, a maximum of twelve productive wells per section is allowed.

7. *Fracturing technology in the NPC base case performs well, but further improvements are assumed in the advanced technology case.*

The following assumptions apply to blanket sands: In the base case, the average achieved propped fracture length is 1000 ft. This is 60% of the created hydraulic length. The fracture height is four times net pay thickness with a minimum of 200 ft and maximum of 600 ft. Fracture conductivity is 500 md-ft. In the advanced technology case the average achieved propped fracture length is 2000 ft for $k \geq 0.1$ md and 4000 ft for $k < 0.1$ md. This is 80% of the created hydraulic length. The fracture height is three times the net pay thickness with a range of 150 ft to 400 ft. Fracture conductivity is 1000 md-ft. The fracture width is assumed to be an ellipse in both horizontal and vertical planes, following the Perkins-Kern model of fracture geometry.[20,22]

8. *Fractures in lenticular formations are assumed to penetrate lenses remote from the well bore.*

The economics of recovering gas from lenticular deposits depends on the average number of lenses that can be produced per well. However, it is quite difficult to control fractures through zones where rock characteristics change (e.g., from shale to sandstone) in order to contact remote lenses. This problem is a topic of current research.

9. *Each wildcat well is fractured in order to estimate reservoir characteristics.*

The wildcat well is fractured so that before a field is developed, initial wildcat well production can be observed and the reservoir properties, such as <u>in situ</u> permeability and achieved fracture length, can be estimated using pressure transient data and other techniques. It is difficult to explicitly model the risk of long-term interpretation error in these tests.[46]

*10. Cost estimates are presented for each SA.**

Components of cost include geology and geophysics ($/prospect), drilling costs ($/well), fracture cost ($/well), surface equipment ($/well), fixed annual operating expense ($/well), and the percentage of gas needed to fuel compressors.

Expected drilling costs were estimated by NPC using Joint Association Survey (1977) data on the costs of drilling and completing gas wells. The costs are reported by region and depth of well. The 1977 costs were escalated by NPC to January 1, 1979, dollars assuming 12% annual inflation in drilling costs. Average drilling costs, escalated to midyear 1981 dollars, are shown by basin in Table 2 (the procedure used is described in Sec. 2.4.1). The costs vary from $100,000 in Northern Great Plains to $2.8 million in Edwards Lime Trend.

The base case MHF design of a 1000-ft propped length and 200-ft height uses 165,000 gallons of fracture fluid. Using NPC graphs, Argonne determined that fracture costs were taken to be approximately proportional to frac fluid volume. Figure A.1 shows the derived NPC cost relationship (solid line) and the similar proportional relationship (dashed line). A 200-ft high fracture in Northern Great Plains costs about $84,000. Adjustment factors are used to increase the costs for more difficult locations or deeper formations. For net pay thicknesses greater than 50 ft, the fracture height is increased to four times the pay thickness. The cost of additional fracture fluid is included.

Surface equipment includes gathering pipeline costs within the field. In the Northern Great Plains and Williston basins, compressors are required at the wellhead and the added costs are included.

11. Economic/financial assumptions are based on a representative situation.

The royalty is taken to be one-eighth of production. The following taxes are assumed: a 46% federal income tax; 2% state income tax; production, severance and property taxes equal to 8% of producer revenue; and 10% federal investment tax credit on tangible equipment. The leasehold cost is modeled as $0.01/MCF. Unit of production depletion allowance was used to recover these leasehold costs. Dry hole costs were charged against successful wells. Intangible costs are 70% of total drilling and development costs. These intangible costs are expensed when they are incurred. Tangible costs are capitalized and amortized using sum-of-years-digits depreciation. Overhead

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*The development of cost estimates is discussed in Chapter 4 and Appendix D of the NPC study.[6]

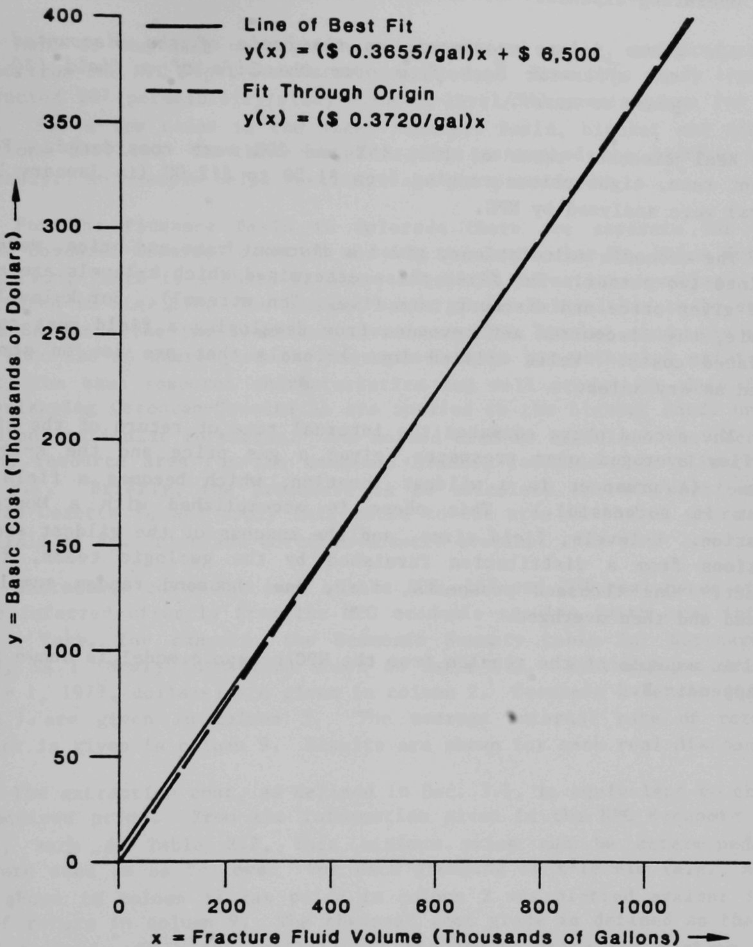

Fig. A.1 Fracture Costs as a Function of Fluid Volume Derived from the NPC *Tight Gas Reservoirs* Report (See Ref. 6 Appendix D) costs are included and are computed as 10% of invested capital and 20% of direct operating expense.

> 12. *Firms judge investments on the basis of the discounted net after-tax cash flow over the life of a field (30 years or more).*

Real discount rates of 10%, 15% and 20% were considered. For each discount rate, eight prices ranging from \$1.50 to \$12.00 (in January 1, 1979, dollars) were analyzed by NPC.

The economic calculations, given a discount rate and price, were separated into two phases. The first phase determined which k-levels are economic at the given price and discount rate (i.e., "on stream"). For k-levels to be economic, the discounted net revenues from developing a field must cover the associated costs. Wells drilled into k-levels that are not on stream are treated as dry holes.

The second phase computes the internal rate of return of the after-tax cash flow averaged over prospects, given a gas price and the k-levels on stream. (A prospect is a wildcat location, which becomes a field if the wildcat is successful.) This phase is accomplished with a Monte Carlo simulation. K-levels, field sizes, and the success of the wildcat are random selections from a distribution furnished by the geologic teams, for each prospect. One thousand prospects, i.e., one thousand random samples, are analyzed and then averaged.

An example of the results from the NPC economic model is shown in Table B.2, Appendix B.

APPENDIX B
METHODOLOGY USED TO CONSTRUCT THE EXTRACTION COST DATA BASE

Many of the data on tight sands gas cost, supply, and production are derived from the NPC *Tight Gas Reservoirs* study.[6] From this study Argonne has constructed 207 permeability/study area (k-level/SA) combinations for blanket sands. For a few cases in the Rocky Mountain Basin, blanket and lenticular formations overlap. In these cases Argonne estimated the blanket resource separately. An example helps to illustrate the procedure.

For the Piceance Basin in Colorado there are separate SAs for the blanket Corcoran-Cozette formation and for the lenticular Ft. Union formation. In addition, there is a third SA where these two formations overlap. This is illustrated in Fig. B.1. The blanket sands gas by k-level had to be estimated in the SA where the two formations overlap. This blanket sands gas was then added into the SA where just the Corcoran-Cozette gas potential exists. As a result, the same resource characteristics and well production data from the nonoverlapping Corcoran-Cozette SA are applied to the blanket sands under the Ft. Union lenticular formation. The method used to calculate the recoverable gas and resource area for the combined blanket formations is illustrated in Table B.1. Briefly, the procedure is to calculate the BCF/section in the Corcoran-Cozette SA and apply this ratio to the area in the SA where the gas potentials of Ft. Union and Corcoran-Cozette overlap.

Extraction costs for each of the 10%, 15% and 20% real rates of return can be inferred directly from the NPC economic results (with some interpolation). Take, for example, the Economic Summary table for Northern Great Plains, SA 1 (Mowry formation) shown in Table B.2. Wellhead gas prices (in January 1, 1979, dollars) are given in column 2. Economic k-levels (i.e., "on stream") are given in column 5. The average internal rate of return per prospect is given in column 9. Results are shown for each real discount rate.

The extraction cost, as defined in Sec. 3.1, is equivalent to the minimum required price. From the information given in the NPC Economic Summary tables, such as Table B.2, this minimum price can be determined. The procedure used is as follows: For each grouping of k-levels (e.g., AB, ABC, etc., shown in column 5) gas price in column 2 was plotted against internal rate of return in column 9. The cheapest cost grade is defined as the grouping of k-levels which are available at the lowest price for a given rate of return. For example as shown in Fig. B.2 for the Mowry study area in Northern Great Plains, grouping AB results in a cheaper cost grade than grouping ABC. That is, at say a 15% rate of return, AB can be extracted at \$4.84 but ABC must be extracted at the higher price of \$5.43. This result should not be interpreted as meaning the developer can selectively find only the better permeabilities. Instead, it is a matter of which wildcat wells are considered dry. That is, when a wildcat strikes permeability C should it be developed (i.e., the ABC case) or left as dry (i.e., the AB case). In conclusion, extraction costs are obtained from graphs like Fig. B.2 by interpolation.

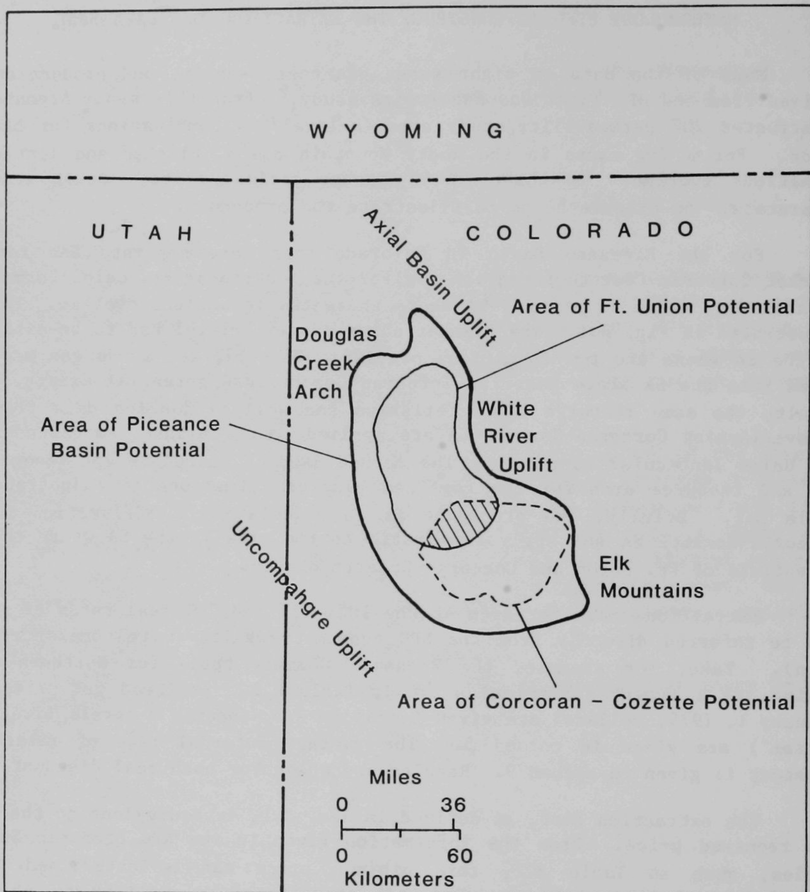

Fig. B.1 Corcoran-Cozette and Ft. Union Areas of Gas Potential Highlighting the Section where the Formations Overlap -- Piceance Basin, Colorado

Table B.1 Calculation of Maximum Recoverable Blanket Sands Gas in the Corcoran-Cozette Formation -- Piceance Basin, Colorado

	Corcoran-Cozette Study Area			Overlapping Corcoran-Cozette/ Ft. Union Study Area		
k-level	Area (mi^2)	Max Rec. Gas (BCF)	Ratio (BCF/mi^2)	Area (mi^2)	Estimated Max Rec. Gas (BCF)[a]	Combined Max Rec. Gas (BCF)
0.1	22	98	4.45	3	13	111
0.03	81	429	5.30	11	58	487
0.01	122	764	6.26	17	106	870
0.003	100	681	6.81	14	95	776
0.001	33	244	7.39	5	37	281
0.0003	11	78	7.09	2	14	92

[a]Calculated as RATIO times AREA in Corcoran-Cozette/Ft. Union study area.

Specifically for the Mowry formation, the real rates of return of 10%, 15% and 20% correspond with extraction costs of \$3.69, \$4.84 and \$6.02 in Jan. 1, 1979, dollars. For a k-level like "D" that comes on stream at higher prices (presumably just earning the required return at the margin), this higher price is taken to be its extraction cost.

The amount of resource available at each minimum price is shown in columns 10 and 11 of Table B.2. The amount in column 10 is based on a maximum of four wells per section. Also shown in Table B.2 are the following: percentage of the 1000 sample prospects that were profitable (column 3); the average gas produced over the 1000 sample prospects (column 7); the wildcat success rate (column 13); and the expected number of wildcat and development wells (columns 14 through 18). The expected number of wells are those needed to produce the recoverable resource shown in column 10.

									0	
				[illegible]	–	0	0	0	3.4	
1	A	1349	1.373	-343	–	..	..	..	3.4	
2	AB	2925	3.429	-376	–	..	..	..	8.8	
	AB	2925	3.429	52	15.7	614	614	178	8.8	[illegible]
	ABC	6117	5.990	804	21.8	937	937	157	15.3	[illegible]
	ABCD	7605	6.943	1778	27.9	1054	1132	151	18.2	[illegible]
	ABCDE	8245	7.217	3463	38.8	1105	1290	153	19.8	[illegible]
	–	630	–	-399	0.0	0	0	0	0	
	–	630	–	-399	0.0	..	..	..	0	[illegible]
	A	1349	1.373	-407	5.4	..	..	..	3.4	[illegible]
	A	1349	1.373	-374	6.9	..	..	..	3.4	..
2	AB	2925	3.429	-212	15.7	..	..	..	8.8	..
3	ABC	6117	5.990	161	21.8	937	937	157	15.3	259
3	ABC	6117	5.990	901	30.5	..	..	..	15.3	..
4	ABCD	7605	6.943	2049	40.5	1054	1132	151	18.2	240

	E	F
1	0.003	0.001

Table B.2 National Petroleum Council (NPC) Economic Summary Table
for Northern Great Plains, Study Area 1, Mowry Formation
(January 1, 1979 Dollars)

BASIN Northern Great Plains - Williston
SUB BASIN 1
FORMATION Mowry
TECHNOLOGY Base Case
DATA June 1980

			K-Levels On Stream		Average Per Prospect				Basin Totals			Wells					
													Wildcat		Development		
Case No.	Gas Price $/MCF	Profit. Prosp. %	No.	Value[a]	E&P Invest. $M	Gas Prod. BCF	Net Pres. Value $M	DCF Rate of Return %	Gas Recover. at Price, BCF	Max Recov. GIP, BCF	Max. No. Prosp. at Price	Wildcat Success %	Dry	Prod.	Dry	Prod.	Total
Discount Rate 10%																	
12011 11	1.50	0	0	0	630	0	-382	0.0	0	0	0	0	0	0	0	0	0
21	2.50	6.7	1	A	1349	1.373	-325	2.90	–	–	–	3.4	–	–	–	–	–
31	3.10	17.1	2	AB	2925	3.429	-248	7.20	–	–	–	8.8	–	–	–	–	–
41	3.50	17.1	2	AB	2925	3.429	-790	9.10	–	–	–	8.8	–	–	–	–	–
51	5.00	29.8	3	ABC	6117	5.990	536	13.1	937	937	157	15.3	259	47	656	2624	3586
61	7.00	35.5	4	ABCD	7605	6.943	1941	19.5	1054	1132	151	18.2	240	53	801	3201	4296
71	9.00	35.5	4	ABCD	7605	6.943	3627	27.9	"	"	"	18.2	"	"	"	"	"
81	12.00	38.6	5	ABCDE	8245	7.217	6173	38.8	1105	1290	153	19.8	238	59	886	3543	4727
Discount Rate 15%																	
12	1.50	0	0	0	630	–	-391	–	0	0	0	0	0	0	0	0	0
22	2.59	6.7	1	A	1349	1.373	-412	–	0	0	0	3.4	0	0	0	0	0
32	3.10	6.7	1	A	1349	1.373	-343	–	"	"	"	3.4	"	"	"	"	"
42	3.50	17.1	2	AB	2925	3.429	-376	–	"	"	"	8.8	"	"	"	"	"
52	5.00	17.1	2	AB	2925	3.429	52	15.7	614	614	178	8.8	31[illegible]	[illegible]	310	1243	1901
62	7.00	29.8	[illegible]	ABC	6117	5.990	804	21.8	937	937	157	15.3	25[illegible]	[illegible]	656	2624	3586
72	9.00	35.5	[illegible]	ABCD	7605	6.943	1778	27.9	1054	1132	151	18.2	24[illegible]	[illegible]	801	3201	4296
82	12.00	38.6	[illegible]	ABCDE	8245	7.217	3463	38.8	1105	1290	153	19.8	23[illegible]	[illegible]	886	3543	4727
Discount Rate 20%																	
13	1.50	–		–	630	–	-399	0.0	0	0	0	0			0	0	0
23	2.50	–		–	630	–	-399	0.0	"	"	"	0			"	"	"
33	3.10	6.7		A	1349	1.373	-407	5.4	"	"	"	3.4			"	"	"
43	3.50	6.7		A	1349	1.373	-374	6.9	"	"	"	3.4			"	"	"
53	5.00	17.1		AB	2925	3.429	-212	15.7	"	"	"	8.8			"	"	"
63	7.00	29.8		ABC	6117	5.990	161	21.8	937	937	157	15.3	2[illegible]	[illegible]	656	2624	3586
73	9.00	29.8		ABC	6117	5.990	901	30.5	"	"	"	15.3		"	"	"	"
83	12.00	35.5	4	ABCD	7605	6.943	2049	40.5	1054	1132	151	18.2	240	53	801	3201	4296

[a]CODE: A 0.3, B 0.1, C 0.03, D 0.01, E 0.003, F 0.001

Table [illegible] National Petroleum [illegible]
for Northern Great Plains
([illegible])

BASIN Northern Great Plains
SUB BASIN [illegible]

Case No.	Gas Price $/MCF	Profit. Prosp. %	[illegible]	[illegible]	Total
Discount Rate 10%					
[illegible]	[illegible]	[illegible]	[illegible]	0	0
[illegible]	[illegible]	[illegible]			[illegible]
31	3.10	[illegible]			[illegible]
41	3.50	[illegible]			[illegible]
51	5.00	[illegible]	[illegible]	[illegible]	3586
61	7.00	[illegible]	[illegible]	[illegible]	4296
71	9.00	[illegible]			[illegible]
81	12.00	[illegible]		[illegible]	4727
Discount Rate 15%					
12	1.50	[illegible]			[illegible]
22	2.50	[illegible]		0	[illegible]
32	3.10	[illegible]			[illegible]
42	3.50	[illegible]			[illegible]
52	5.00	[illegible]	[illegible]	[illegible]	1931
62	7.00	[illegible]	[illegible]	[illegible]	3585
72	9.00	[illegible]	[illegible]	[illegible]	4296
82	12.00	[illegible]	[illegible]	[illegible]	4727
Discount Rate 20%					
13	1.50				0
23	2.50				[illegible]
33	3.10	[illegible]			[illegible]
43	3.50	[illegible]			[illegible]
53	5.00	[illegible]			[illegible]
63	7.00	[illegible]	[illegible]	[illegible]	3586
73	9.00	[illegible]			[illegible]
83	12.00	[illegible]	[illegible]	[illegible]	4296

Note: A B C [illegible]
[illegible] 0.1 0.[illegible] [illegible]

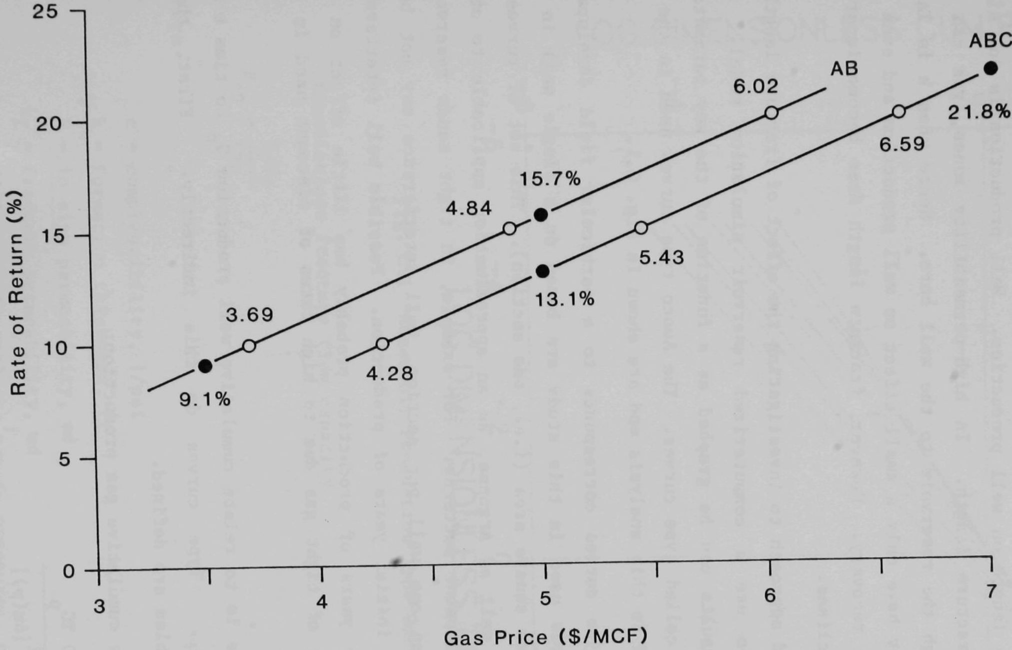

Fig. B.2 Illustration of Methodology Used to Interpolate Extraction Costs from Published NPC Results -- Northern Great Plains, Mowry Formation (SA 1)

APPENDIX C
TIGHT SANDS GAS WELL PRODUCTION AND TYPE CURVE ANALYSIS

This appendix presents the method used to determine the impact of effective fracture length on well production. Well production is not simply proportional to fracture length. In high-permeability zones, gas can more easily flow through the reservoir to the well bore. Hence when k is large, fracture length may have only a small effect on well production and even less effect on ultimate recovery. However, fracture length does become important as permeability declines.

The standard approach to investigating the effect of fracture length on well output is to use a computerized reservoir simulation model. For convenience the results can be graphed as a function of the key parameters. These graphs are called type curves. The Amoco type curves used in the NPC study are also used in this analysis and are shown in Fig. C.1.

A set of type curves corresponds to a particular field development pattern. The curves used in this study are based on a single well in the center of a 640-acre square area (i.e., one section). This set of curves is viewed by NPC, as well as Argonne, as an approximation applicable to other similar field development patterns. For example, in tight sands reservoirs even with more than one well per section, well interference may not be a problem during the initial years of production. Possible well interference occurring in later years of production probably has little effect on the economic assessment of tight gas due to high rates of discount used in the economic analysis.

The objective is to relate cumulative well production G_p to time t and fracture length x_f. Type curves do this indirectly. First, three dimensionless variables are defined.

Dimensionless cumulative gas production:

$$G_{pD} = \frac{9000\ TG_p}{h\phi\mu c x_f^2 [\Delta m(p)]}$$

Dimensionless time:

$$t_{Dx_f} = \frac{2.634 \cdot 10^{-4}\ kt}{\phi\mu c x_f^2}$$

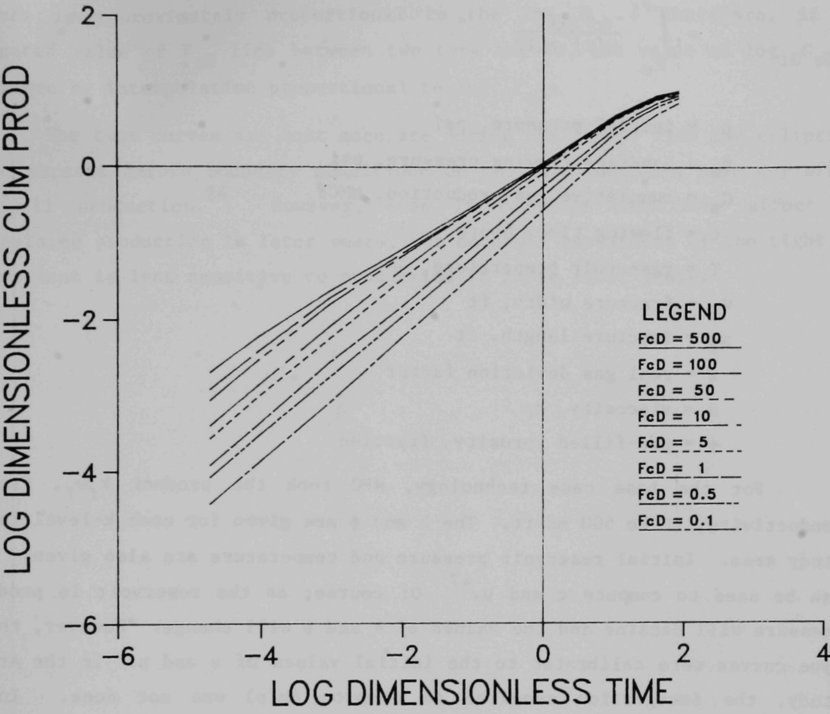

Fig. C.1 Reservoir Production Type Curves

Dimensionless fracture flow capacity:

$$F_{cD} = \frac{k_f w_f}{k x_f}$$

where

c = compressibility, 1/psi

h = formation thickness, ft

k = in situ permeability, md

k_f = fracture permeability, md

$\Delta m(p)$ = difference in real gas psuedo pressures, psi^2/cp

$$= \int_{p_w}^{p_i} \frac{\tau \, d\tau}{\mu(\tau) \; z(\tau)}$$

p_i = initial pressure, psi

p_w = sandface flowing pressure, psi

G_p = cumulative gas production, MMCF

t = flowing time, hours

T = reservoir temperature, °R

w_f = fracture width, ft

x_f = fracture length, ft

z = real gas deviation factor

μ = viscosity, cp

ϕ = gas-filled porosity, fraction

For the base case technology, NPC took the product $k_f w_f$, fracture conductivity, to be 500 md-ft. The h and ϕ are given for each k-level in each study area. Initial reservoir pressure and temperature are also given. These can be used to compute c and μ.[47] Of course, as the reservoir is produced, pressure will decline and the values of c and μ will change. However, the NPC type curves were calibrated to the initial values of c and μ. In the Argonne study, the integration required to compute $\Delta m(p)$ was not done. Instead cumulative production after 8766 hours (one year) was matched to the published NPC result using x_f = 1000 ft. Following NPC, the first 14 days of production were assumed to be required for cleaning out the frac fluid. This production is deleted from the commercial gas production.

Specifically, the type curve analysis goes as follows: let the fracture length x_f = 1000 ft. Compute F_{cD}, which equals 5 if k = 0.1. This value identifies the appropriate type curve. Next, for each year from 1 to 30 compute t_{Dx_f}. The $\log_{10} t_{Dx_f}$ is plotted on the horizontal axis of the type curves. Then for each year, $\log_{10} G_{pD}$ is read off the vertical axis using the appropriate type curve. Actual cumulative production G_p can then be computed from the equation for G_{pD}. Annual production is obtained by differencing cumulative production.

As the fracture length is decreased, both F_{cD} and t_{Dx_f} increase (holding t fixed); that is, one moves upward along a type curve as well as upward shifting to a higher type curve. The shift in the family of type curves is approximately proportional to the $\log_{10}F_{cD}$. Therefore, if the computed value of F_{cD} lies between two type curves, the value of $\log_{10}G_{pD}$ is obtained by interpolation proportional to $\log_{10}F_{cD}$.

The type curves are most accurate during the linear flow and elliptical flow phrases before boundary conditions on the drainage area have any effect on well production.[24] However, even if boundary conditions affect the calculated production in later years, the economic assessment of the tight gas investment is less sensitive to production in those later years.

APPENDIX D
ARGONNE MODELING SYSTEM, DATA BASE AND REPORT WRITERS

The Argonne GCOST system consists of various data bases and associated models for projecting tight sands gas extraction cost, resource supply characteristics, tight gas sands production and market demand. Only the extraction cost, resource supply, and tight gas sands production information will be mentioned here. Tight sands gas demand was examined elsewhere.[7] The tight gas sands production data were not used in this report but were used in an earlier analysis to support the GRI Energy Systems Economics program.[48] Below are listed the components of the tight sands gas data base and models by category:

EXTRACTION COST DATA

- Argonne has estimated extraction costs from the published results of the NPC economic model. Extraction costs are given at 10%, 15% and 20% real rates of return using 1000-ft fractures.

- The Argonne TGSDIST model is used to compute revised extraction costs as a function of effective fracture length.

RESOURCE SUPPLY DATA

- Formation descriptions

- NPC productive areas

- NPC maximum recoverable gas

- NPC well production data for 1000-ft fractures

- Argonne TYPE model designed to employ Amoco type curves in well production calculations

- Resource characteristics: <u>in situ</u> permeability, gas-filled porosity, net pay thickness, depth, temperature, pressure, compressibility, and viscosity.

TIGHT GAS PRODUCTION DATA

- NPC estimated drilling schedule by study area
- Average wildcat dry hole ratios
- Average development wells per prospect
- FERC Form 121 data, based on applications by well for tight sands gas pricing under Sec. 107 of the NGPA of 1978. These data include projected production from each tight formation well.
- State specific annual data (1960-1982) on gas production, exports, imports, interstate movements, demand by end-user and storage of natural gas and supplemental gas based on EIA forms 176, 627 and 64.

GCOST System Report Writers

Several report writers developed by Argonne can present input data and results in a clear, understandable tabular form. Table D.1 is an example of such a report. Using a 15% real rate of return, the extraction costs are compared for achieved fracture lengths of 800 ft and 1000 ft. The table also shows maximum recoverable gas by cost grade. The constrained recoverable gas, allowing at most four wells per section, may depend on achieved fracture length. With a shorter fracture length, 30-year ultimate recovery per well may be less so that the recoverable resource with four wells per section may be less.

In addition, Table D.1 makes clear the concept that cost grades are, in general, comprised of multiple k-levels that become economic as a group at a price equal to the extraction cost. The k-levels comprising each cost grade are shown in the right hand side column of Table D.1.

Note that the lowest extraction cost grade appears to be in the Coaly formation in Uinta Basin, Utah. For this formation, k-levels, in the range of 0.3 to 0.01 md, can be extracted as a group for $1.50/MCF in midyear 1981 dollars with a technology of 1000-ft average achieved propped fracture length.

Table D.1 Cost Grades and Recoverable Blanket Resource for 15% Real Rate of Return and Two Fracture Lengths

Model: ANL-GCOST-Blanket-R15-FL800
Parameters: Real Rate of Return = 15 Percent
Achieved Propped Fracture Lengths = 800 ft, 1000 ft

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
NGP	1	6.42	7.03	9.6	618.	618.	618.	1 MOWRY	0.3000	0.1000		
NGP	1	8.40	9.78	16.3	321.	318.	270.	1 MOWRY	0.0300			
NGP	1	11.95	14.14	18.4	195.	116.	98.	1 MOWRY	0.0100			
NGP	2	2.96	3.30	11.6	1666.	1666.	1666.	2 MOWRY,GREENHORN	0.3000	0.1000	0.0300	
NGP	2	4.11	4.87	18.4	329.	288.	244.	2 MOWRY,GREENHORN	0.0100			
NGP	2	5.97	7.12	19.2	215.	114.	96.	2 MOWRY,GREENHORN	0.0030			
NGP	2	9.29	11.34	22.1	12.	4.	3.	2 MOWRY,GREENHORN	0.0010			
NGP	3	2.56	2.89	12.7	2187.	2187.	2187.	2 MOWRY,CARLILE	0.3000	0.1000	0.0300	
NGP	3	2.99	3.54	18.4	701.	569.	482.	2 MOWRY,CARLILE	0.0100			
NGP	3	5.80	6.92	19.2	600.	271.	229.	2 MOWRY,CARLILE	0.0030			
NGP	3	6.63	8.10	22.1	34.	9.	8.	2 MOWRY,CARLILE	0.0010			
NGP	4	2.18	2.47	13.6	8742.	8362.	8127.	3 MOWRY,GHORN,CARL	0.3000	0.1000	0.0300	0.010
NGP	4	4.11	4.91	19.3	1515.	677.	571.	3 MOWRY,GHORN,CARL	0.0030			
NGP	4	6.63	8.10	22.2	74.	20.	16.	3 MOWRY,GHORN,CARL	0.0010			
NGP	5	1.85	2.09	13.0	9360.	8928.	8689.	4 M,G,C,EAGLE	0.3000	0.1000	0.0300	0.010
NGP	5	4.11	4.91	19.3	2671.	1162.	979.	4 M,G,C,EAGLE	0.0030			
NGP	5	8.40	10.27	22.2	134.	35.	29.	4 M,G,C,EAGLE	0.0010			

Table D.1 (Cont'd)

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
NGP	6	2.70	3.02	11.3	3249.	3249.	3118.	3 MOWRY,GHORN,EAGL	0.3000	0.1000	0.0300	
NGP	6	3.32	3.93	18.5	771.	477.	402.	3 MOWRY,GHORN,EAGL	0.0100			
NGP	6	6.63	7.93	19.5	1304.	450.	379.	3 MOWRY,GHORN,EAGL	0.0030			
NGP	6	11.95	14.61	22.4	62.	13.	11.	3 MOWRY,GHORN,EAGL	0.0010			
NGP	7	3.50	3.94	12.5	2770.	2770.	2770.	2 MOWRY,JUDITH RIV	0.3000	0.1000	0.0300	
NGP	7	4.11	4.87	18.4	1013.	845.	714.	2 MOWRY,JUDITH RIV	0.0100			
NGP	7	6.63	7.91	19.2	998.	462.	390.	2 MOWRY,JUDITH RIV	0.0030			
NGP	7	11.05	13.51	22.2	55.	15.	13.	2 MOWRY,JUDITH RIV	0.0010			
NGP	8	1.97	2.22	12.8	5571.	5204.	5056.	3 MOWRY,CARL,EAGLE	0.3000	0.1000	0.0300	0.010
NGP	8	4.11	4.91	19.4	1742.	703.	592.	3 MOWRY,CARL,EAGLE	0.0030			
NGP	8	8.40	10.27	22.3	68.	17.	14.	3 MOWRY,CARL,EAGLE	0.0010			
NGP	9	2.51	2.87	14.4	8769.	7847.	7446.	4 MOW,CARL,EAG,JR	0.3000	0.1000	0.0300	0.010
NGP	9	4.64	5.55	19.4	3075.	1192.	1005.	4 MOW,CARL,EAG,JR	0.0030			
NGP	9	9.29	11.37	22.3	122.	29.	24.	4 MOW,CARL,EAG,JR	0.0010			
NGP	10	2.15	2.44	13.2	4546.	4247.	4129.	5 M,G,C,E,JR	0.3000	0.1000	0.0300	0.010
NGP	10	4.64	5.55	19.3	1326.	531.	448.	5 M,G,C,E,JR	0.0030			
NGP	10	9.29	11.37	22.3	62.	15.	12.	5 M,G,C,E,JR	0.0010			
NGP	11	2.63	2.99	13.9	3567.	3311.	3199.	3 MOWRY,CARL,JR	0.3000	0.1000	0.0300	0.010
NGP	11	4.64	5.55	19.4	897.	368.	311.	3 MOWRY,CARL,JR	0.0030			
NGP	11	8.40	10.27	22.3	50.	12.	10.	3 MOWRY,CARL,JR	0.0010			

Table D.1 (Cont'd)

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
NGP	12	4.31	4.70	9.1	1142.	1142.	1142.	1 GREENHORN	0.3000	0.1000		
NGP	12	5.80	6.73	16.1	527.	527.	527.	1 GREENHORN	0.0300			
NGP	12	8.40	9.95	18.4	370.	295.	249.	1 GREENHORN	0.0100			
NGP	13	2.68	3.01	12.3	747.	747.	747.	2 GHORN,CARL	0.3000	0.1000	0.0300	
NGP	13	3.32	3.93	18.5	238.	171.	144.	2 GHORN,CARL	0.0100			
NGP	13	5.97	7.14	19.4	193.	78.	66.	2 GHORN,CARL	0.0030			
NGP	13	9.29	11.36	22.3	10.	2.	2.	2 GHORN,CARL	0.0010			
NGP	14	2.55	2.86	12.2	2936.	2747.	2653.	2 GHORN,EAGLE	0.3000	0.1000	0.0300	0.010
NGP	14	5.97	7.14	19.4	1051.	397.	335.	2 GHORN,EAGLE	0.0030			
NGP	14	11.05	13.53	22.3	49.	11.	9.	2 GHORN,EAGLE	0.0010			
NGP	15	2.39	2.70	13.1	2533.	2349.	2258.	3 GHORN,CARL,EAGLE	0.3000	0.1000	0.0300	0.010
NGP	15	5.97	7.13	19.4	778.	298.	251.	3 GHORN,CARL,EAGLE	0.0030			
NGP	15	9.29	11.37	22.3	42.	10.	8.	3 GHORN,CARL,EAGLE	0.0010			
NGP	16	4.56	5.15	12.7	2265.	2265.	2158.	1 CARLILE	0.3000	0.1000	0.0300	
NGP	16	6.63	7.86	18.5	931.	596.	503.	1 CARLILE	0.0100			
NGP	16	11.95	14.27	19.5	709.	254.	215.	1 CARLILE	0.0030			
NGP	17	2.57	2.85	11.5	6918.	6756.	6653.	1 NIOBRARA	0.3000	0.1000	0.0300	0.010
NGP	17	4.64	5.54	19.2	174.	87.	73.	1 NIOBRARA	0.0030			
NGP	18	3.09	3.46	11.8	1203.	1203.	1158.	2 CARL,EAGLE	0.3000	0.1000	0.0300	
NGP	18	3.47	4.10	18.5	385.	248.	209.	2 CARL,EAGLE	0.0100			
NGP	18	6.63	7.93	19.5	567.	205.	173.	2 CARL,EAGLE	0.0030			

Table D.1 (Cont'd)

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
NGP	19	8.65	9.76	12.7	1480.	1463.	1345.	1 JUDITH RIVER	0.3000	0.1000	0.0300	
NGP	20	2.30	2.59	12.9	2550.	2282.	2200.	2 CARL,NIOBRARA	0.3000	0.1000	0.0300	0.010
NGP	20	5.97	7.13	19.3	904.	256.	216.	2 CARL,NIOBRARA	0.0030			
NGP	20	11.95	14.58	22.0	26.	7.	6.	2 CARL,NIOBRARA	0.0010			
GGR	51	2.30	2.69	16.9	573.	573.	573.	1 L1-ALMOND A	0.3000	0.1000	0.0300	
GGR	51	3.32	3.91	17.9	441.	441.	441.	1 L1-ALMOND A	0.0100			
GGR	51	5.80	6.87	18.5	295.	277.	234.	1 L1-ALMOND A	0.0030			
GGR	51	11.05	13.31	20.4	77.	36.	30.	1 L1-ALMOND A	0.0010			
GGR	54	3.65	4.29	17.6	567.	567.	567.	1 L2/3-ALMOND A	0.3000	0.1000	0.0300	
GGR	54	4.64	5.48	18.0	522.	522.	522.	1 L2/3-ALMOND A	0.0100			
GGR	54	8.40	9.96	18.6	602.	602.	525.	1 L2/3-ALMOND A	0.0030			
GGR	54	11.95	14.40	20.6	346.	197.	164.	1 L2/3-ALMOND A	0.0010			
GGR	56	3.03	3.57	17.9	510.	510.	510.	1 W-ALMOND	0.1000	0.0300	0.0100	
GGR	56	6.63	7.86	18.5	268.	268.	268.	1 W-ALMOND	0.0030			
GGR	56	9.29	11.17	20.3	106.	79.	66.	1 W-ALMOND	0.0010			
GGR	59	4.49	5.25	17.1	4043.	4043.	4043.	1 B,L5,W/2L4-FRONT	0.3000	0.1000	0.0300	0.010
GGR	59	11.95	14.15	18.5	1069.	1069.	1069.	1 B,L5,W/2L4-FRONT	0.0030			
GGR	61	4.49	5.29	17.8	461.	461.	461.	1 SANDWASH-LEWIS70	0.1000	0.0300	0.0100	
GGR	61	5.97	7.08	18.7	375.	288.	244.	1 SANDWASH-LEWIS70	0.0030			
GGR	61	9.29	11.23	20.9	191.	87.	72.	1 SANDWASH-LEWIS70	0.0010			

Table D.1 (Cont'd)

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
GGR	12	5.78	6.82	18.3	788.	721.	662.	1 SANDWASH-LEWIS90	0.1000	0.0300	0.0100	0.003
GGR	12	9.29	11.22	20.8	359.	179.	149.	1 SANDWASH-LEWIS90	0.0010			
UIN	51	1.50	1.77	17.6	2180.	2180.	2180.	1 COALY	0.3000	0.1000	0.0300	0.010
UIN	51	2.99	3.54	18.6	829.	770.	652.	1 COALY	0.0030			
UIN	51	5.80	7.01	20.8	255.	136.	113.	1 COALY	0.0010			
UIN	52	3.54	4.18	18.1	1192.	1192.	1164.	1 CASTLEGATE	0.1000	0.0300	0.0100	0.003
UIN	52	9.29	11.20	20.6	323.	205.	171.	1 CASTLEGATE	0.0010			
PIC	51	2.58	3.03	17.4	2098.	2098.	2098.	1 CORCORAN-COZETTE	0.1000	0.0300	0.0100	
PIC	51	3.84	4.57	18.7	1108.	767.	646.	1 CORCORAN-COZETTE	0.0030			
PIC	51	5.97	7.24	21.2	401.	165.	137.	1 CORCORAN-COZETTE	0.0010			
PIC	51	11.05	13.51	22.2	131.	32.	26.	1 CORCORAN-COZETTE	0.0003			
WIND	1	2.81	3.20	13.8	974.	894.	808.	1 FRONTIER/MUDDY	0.3000	0.1000	0.0300	
WIND	1	4.64	5.50	18.5	403.	215.	181.	1 FRONTIER/MUDDY	0.0100			
WIND	1	8.40	10.04	19.5	170.	52.	44.	1 FRONTIER/MUDDY	0.0030			
DEN	1	9.65	11.44	18.6	656.	456.	401.	1 DEN A-MUDDY J	0.0100	0.0030		
DEN	1	11.95	14.52	21.6	1787.	582.	484.	1 DEN A-MUDDY J	0.0010			
DEN	2	11.66	13.83	18.6	179.	127.	109.	1 DEN B-MUDDY J	0.0100	0.0030		
DEN	2	12.70	15.44	21.6	515.	170.	141.	1 DEN B-MUDDY J	0.0010			

Table D.1 (Cont'd)

Basin	Study Area	Extraction Costs (Midyear 1981 $/MCF) Fracture Length 1000'	800'	PCT Change	MAX Recoverable Gas (BCF)	Constrained Recoverable Gas with 4 Wells/Section 1000'	800'	No. of Overlapping Formations and Formation Names	K-Levels Contained in Cost Grade (Millidarcy)			
COTV	1	2.43	2.87	18.2	5387.	5387.	5240.	1	0.3000	0.1000	0.0300	0.010
COTV	1	4.11	4.96	20.4	1723.	1132.	943.	1	0.0010			
COTV	1	6.63	8.05	21.3	1242.	456.	379.	1	0.0003			
EDLM	1	2.39	2.81	17.9	2354.	2149.	2070.	1 SOUTHWEST	0.2000	0.0600	0.0200	0.006
EDLM	1	5.80	7.03	21.2	604.	250.	207.	1 SOUTHWEST	0.0006			
EDLM	1	11.05	13.51	22.2	140.	34.	28.	1 SOUTHWEST	0.0002			
EDLM	2	4.11	4.86	18.1	4056.	3820.	3668.	1 CENTRAL	0.2000	0.0600	0.0200	0.006
EDLM	2	9.29	11.25	21.0	1048.	491.	408.	1 CENTRAL	0.0006			
VALV	1	5.84	6.99	19.7	369.	154.	132.	1 OZONA	0.0300	0.0100	0.0030	0.001
VALV	1	11.95	14.64	22.6	162.	26.	21.	1 OZONA	0.0003			
VALV	2	4.74	5.59	18.1	844.	516.	454.	1 SONORA	0.3000	0.1000	0.0300	0.010
VALV	2	4.77	5.83	22.1	424.	116.	96.	1 SONORA	0.0010			
VALV	2	9.29	11.38	22.6	346.	55.	45.	1 SONORA	0.0003			
SJ	1	3.51	4.15	17.9	463.	463.	463.	1 SAN JUAN	0.0400	0.0100		
SJ	1	5.80	6.87	18.4	1031.	1031.	970.	1 SAN JUAN	0.0040			
SJ	1	11.96	14.41	20.7	526.	316.	262.	1 SAN JUAN	0.0010			

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